Danish Energy Agency

EMBASSY OF DENMARK

MOIT

EREA

Technical Report for Viet Nam Energy Outlook Report 2021

2021

Technical Report for Viet Nam Energy Outlook Report 2021

2021

Published by:

Ea Energy Analyses
Email: nd@eaea.dk
Web: www.eaea.dk

EML Energy modelling lab
Email: ida@energymodellinglab.com
Web: www.energymodellinglab.com

IE Institute of Energy
Email: lethuhavnl@gmail.com
Web: http://www.ievn.com.vn

Contents

Abbreviations

General abbreviations	
CCUS	Carbon Capture, Utilization and Storage
COVID-19	Coronavirus Disease 2019
COP	Conference of the Parties
DE	Development Engagement
DEA	Danish Energy Agency
Ea	Ea Energy Analyses
EML	Energy Modelling Lab
EOR	Energy Outlook Report
EREA	Electricity and Renewable Energy Agency
FIT	Feed-in Tariff
GWh	Giga Watt-hours
HPP	Hydro Power Plant
IE	Institute of Energy
kWh	Kilo Watt-hours
ktoe	Kilo Tonne of Oil-Equivalent
MOIT	Ministry of Industry and Trade
Mtoe	Mega Tonne of Oil-Equivalent
MWh	Mega Watt-hours
NDC	Nationally Determined Contributions
P2X	Power-to-X
PDP	Power Development Plan
PVN	PetroVietNam (Viet Nam Oil and Gas group)
REDS	Renewable Energy Development Strategy
TPES	Total Primary Energy Supply
TWh	Tera Watt-hours
VRE	Variable Renewable Energy
X2P	X-to-Power
Energy sectors	
AGR	Agriculture
COM	Commercial
IND	Industry
PWR	Power
RSD	Residential
TRA	Transport
Emissions and pollutants	
CO_2	Carbon dioxide
NO_x	Nitrogen oxides
SO_2	Sulphur dioxide
$PM_{2.5}$	Particular Matter 2.5
Main scenarios	
BSL	Baseline
GP	Green Power

GT	Green Transition
AP	Air Pollution
NZ	Net-Zero

Foreword

The analyses described in this report are part of Development Engagement 1 (DE1): "Capacity Development for long-range energy sector planning with Electricity and Renewable Energy Agency of Viet Nam", currently being conducted under the Energy Partnership Programme between Viet Nam and Denmark (DEPP III), a cooperation between the Danish Energy Agency (DEA), the Electricity and Renewable Energy Authority of Viet Nam (EREA) and the Vietnamese Ministry of Industry and Trade (MOIT).

This Technical Report serves as a background report to the Energy Outlook Report for Viet Nam 2021 (EOR21), which analyses a range of energy scenarios to guide decision makers and energy and power system planners to achieve a sustainable green transition of the energy system in a cost-efficient way. The EOR21 builds on the work carried out in the first and second editions of the bi-annual report: the EOR 2017 (MOIT and DEA, 2017) and the EOR 2019 (MOIT and DEA, 2019).

Furthermore, reports supporting this study include:

- Air pollution study of Viet Nam to include air pollution costs in the energy systems models (EML, Ea, and AU 2021)
- Model linking of the energy systems models Balmorel and TIMES (Ea and EML, 2020)
- Fuel Price Projections for Vietnam. Background to the Vietnam Energy Outlook Report 2021. (EREA and DEA, 2021a)
- Vietnamese technology catalogue (EREA and DEA, 2021b)

The document lays out key assumptions, modelling set-up and results of five Main scenarios and a range of sensitivity scenarios. The scenarios are optimised in a modelling framework comprising two energy models: TIMES (encompassing supply, conversion, and end-use sectors) and Balmorel (representing the power sector in high technical, temporal, and geographical detail). Furthermore, the power grid model PSS/E has been applied to strengthen the conclusions regarding the power grid.

This report is written by Ea Energy Analyses (Ea), Energy Modelling Lab (EML), E4SMA, and Institute of Energy (IE) in close cooperation with EREA, the DEA and many national stakeholders.

Executive summary

Economic growth drives growth in the energy sectors

In the past years, Viet Nam has experienced high economic growth rates of about 6-7% annually. The COVID-19 health crisis has had a negative effect on economic growth for 2020 but is not expected to have a lasting impact and growth rates are predicted to bounce back quickly, projected to stay above 6% annually until 2035 and then gradually decreasing to 5.25% annually by 2050. The rapid increase in Vietnam's GDP drives consumption growth in all energy sectors. Supplying the expanding energy sectors is seen as one of the main challenges for Vietnam's future energy system.

Modelling suite

The analysis reported in this document is based on simulation results from three energy models: TIMES, Balmorel and PSS/E. Both TIMES and Balmorel are least-cost optimization models. The TIMES model optimises all energy sectors with a wide scope, allowing for analysis of electrification of other sectors, sector coupling and allocation of resources between sectors. The Balmorel model performs a more detailed optimization of the power system only and is ideally suited to assess integration of variable renewables, need for transmission expansions and flexibility in terms of batteries. The PSS/E model is used to investigate the Vietnamese grid and assess future grid reinforcement needs.

Electrification and modal shift in the transport sector help reducing emissions

Electrification can add to the reduction of CO_2 emissions in the end-use sectors by increase deployment of variable renewables in the power system. In the GT scenario, electrification of the transport sector increases the total power demand by 10%. A modal shift in the transport sector combined with renewable supply for the increased power demand from transport electrification, results in a reduction of 5.9% in the total CO_2 emissions.

Heath costs related to air pollution

Both TIMES and Balmorel keep track of the economic costs of air pollution. The study indicates that considering these external costs connected to pollution in the least-cost optimization, leads to increased energy efficiency and an accelerated coal phase-out. By doing so the pollution costs are reduced from 13.2 billion USD to 12 billion USD. Scenarios with increased green ambitions, are seen to also show the added advantage of reduced pollution and related health costs due to reduced coal generation, with 1.6 billion USD in the Net-zero scenario.

Potential role for biofuels

The study shows that there is a significant benefit of utilising biofuels in the energy system in Viet Nam – between 340 and 410 TWh of primary fuel use. These biofuels are synthesized from domestic biomass resources such as straw and bagasse. Biofuels can contribute to a greener energy sector by replacing gasoline and diesel in the end-use sectors.

Wind and solar play a large role in the future power sector.

Viet Nam has abundant high-quality variable renewable energy resources such as onshore wind, offshore wind and solar irradiation. The analysis shows that the considerable utilisation of these resources in the power sector is part of the least-cost solution, with RE shares of 34% and 51% in 2030 and 2050 respectively. Notably, solar power contributes largely to the power mix in the mid to long-term future, especially in more ambitious green scenarios with 73% solar generation in the Net-zero scenario (21% wind).

Batteries and grid expansion integrate variable renewables

To successfully integrate RE in the power system, expansions in the transmission grid are needed. Transmission corridors enable the best quality wind and solar resources from the South to reach the demand centre of Hanoi in the North. Installations of significant battery capacity is also shown to go together with increases in solar PV utilisation. The results show 25 GW in the BSL scenario. Pumped hydro storages have a role in storing energy in case of very high RE penetration in the power sector, up to 9 GW.

Full decarbonisation

In the Net-zero scenario, a net-zero carbon emissions target was implemented in all energy sectors by 2050. The analysis shows that reaching this ambitious target requires large contributions of energy efficiency, lowering the final energy consumption to a minimum. The industrial sector sees the biggest change with energy efficient solutions having a market share of more than 95% in 2050, resulting in a reduction in the final energy consumption of more than 1,000 PJ. Additionally, to the extent possible, electrification of the different sectors is needed, resulting in a much larger power system. This power system is seen to exploit the full solar potential for both traditional fixed-mount PV and rooftop PV and roughly 65% of the full wind potential in Vietnam, relying on existing reservoir hydro, 437 GW batteries, and 9 GW pumped hydro to balance the system. In the current modelling suite, full decarbonisation was not achieved due to constraints in the set-up. The remaining carbon emission by 2050 was 65 $MtCO_2$.

Future work: P2X and decarbonisation technologies

A comprehensive representation of synthetic fuels, biofuels and the production hereof would allow the modelling suite to assess the role of these fuels in the Vietnamese energy system. Modelling power-to-X would allow for a further indirect electrification of the hard-to-decarbonise energy sectors such as transport and industry.

1 Introduction

Vietnamese energy landscape

During the last decades, Viet Nam has experienced economic growth, industrial development, urbanisation, increased transport demand, improved energy access, and rising living standards, all of which are major drivers for growing energy consumption.

For the period 2011-2020, average economic growth was 5.95%/year. In the five-year period from 2011 to 2015, the average growth rate decreased sharply compared to the previous periods, reaching only 5.9%/year. In the period 2016 - 2019, the growth rate recovered, reaching a much higher level, of on average 6.78%/year. In 2020, because of the COVID-19 pandemic, Viet Nam economic growth rate was only 2.91% (DSI, 2021).

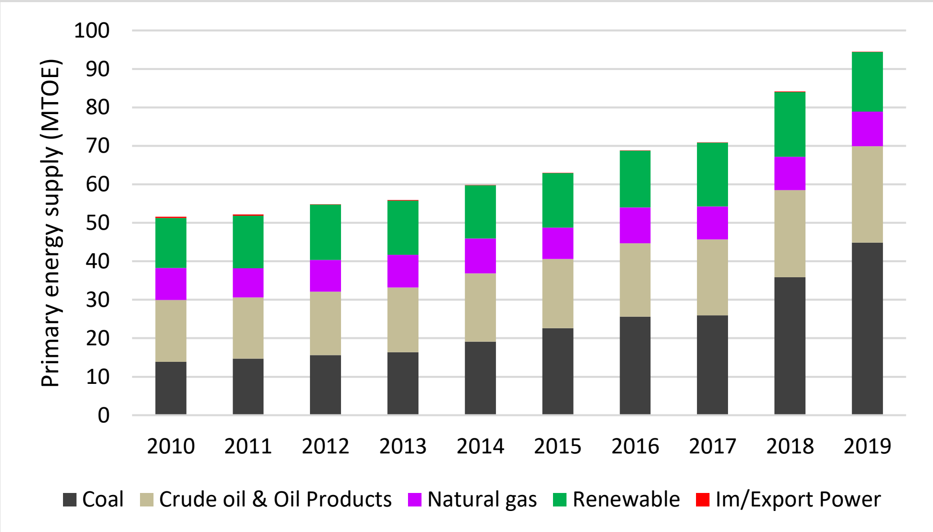


Figure 1: Historical primary energy supply (TPES) of Vietnam

In 2019, Vietnam's total primary energy supply (TPES) was 96 Mtoe, an increase of 12.3% compared to 2018, see Figure 1. Meanwhile, for the whole period of 2010-2019, the growth rate was only 7.0% annually. The main driver for TPES growth is the economic development. The other important factor is the energy transformation, mainly in the electricity sector. The dramatic increase in primary energy supply in recent years has been most pronounced for coal-fired power (VNEEP, 2021).

During the period 2010-2019 non-commercial energy in the TPES declined sharply from 13.7% in 2010 to 4.9% in 2015 and only 2.8% in 2019. Renewable energy, including hydropower, is 25.1% in 2010 to 22.4% in 2015 and 20.0% in

2018. In 2019 renewable energy decreased to only 16.4% despite the rapid increase in solar power.

The most significant development concerns coal. In 2010, coal accounted for only 26.8% of the capacity and increased steadily in the few years after. However, after 2015, coal increased significantly, to 42.6% in 2018 and a record 47.5% in 2019 in total supply.

In 2019, domestic commercial energy exploitation reached 58 Mtoe. Domestic coal accounted for the largest portion with 38.4%, lower than in 2010 (45.6%). The second largest domestic fuel is crude oil, accounting for 19.2% of the total commercial energy exploitation. The share of crude oil has continuously decreased since its peak in 2014. For the whole period 2010-2019, renewable energy increased by average 2.1% annually, while hydroelectricity achieved a slightly lower growth rate of 10.2% annually.

Energy exports have decreased in recent years, while imports have increased. The exported energy in 2019 was only 8.1 Mtoe, 2.6 times less than 2010. Meanwhile, the amount of imported energy, after a few years of decline due to the fall in domestic demand, has increased sharply since 2015, which is also the first year that Viet Nam officially became a net energy importer. In terms of volume, in 2019, imported energy was 46 Mtoe, an increase of 41.6% compared to 2018. For the whole period of 2010-2019, imported energy growth was 15.6%/year. Overall, net energy imports share in TPES increased from 6.0% in 2015 to 39.6% in 2019.

Vietnamese power sector

By the end of 2020, the Vietnamese power system became the second largest in South-East Asia (after Indonesia) and ranking 23rd in the world. Vietnam's power system is one of the fastest growing power systems in the world. The sold electricity in 2020 reached 216.8 TWh, an increase of 2.5 times compared to 2010 (85.6 TWh), corresponding to the average growth of sold electricity in the 2011-2020 period is 9.7%/year (10.9%/year in 2011-2015 and 8.62%/year in 2016-2020). The impact of the COVID-19 pandemic has also caused a slowdown in the growth of power demand in 2020, reaching only 3.4%/year. In 2020, peak load of the whole system reached 38.6 GW, the peak load growth is in line with the growth rate of electricity sales.

Vietnam's electricity system had a total installed capacity of about 69 GW (including rooftop solar power) in 2020. About 21 GW of coal-fired thermal power accounts for about 30%, CCGTs and oil-fired thermal power plants have about

9 GW (13%), hydro power plants with total capacity of 20.9 GW (about 30%), solar power (including rooftop solar power) about 17 GW (24%), wind, biomass and imported power with total capacity about 1.4 GW (about 2%).

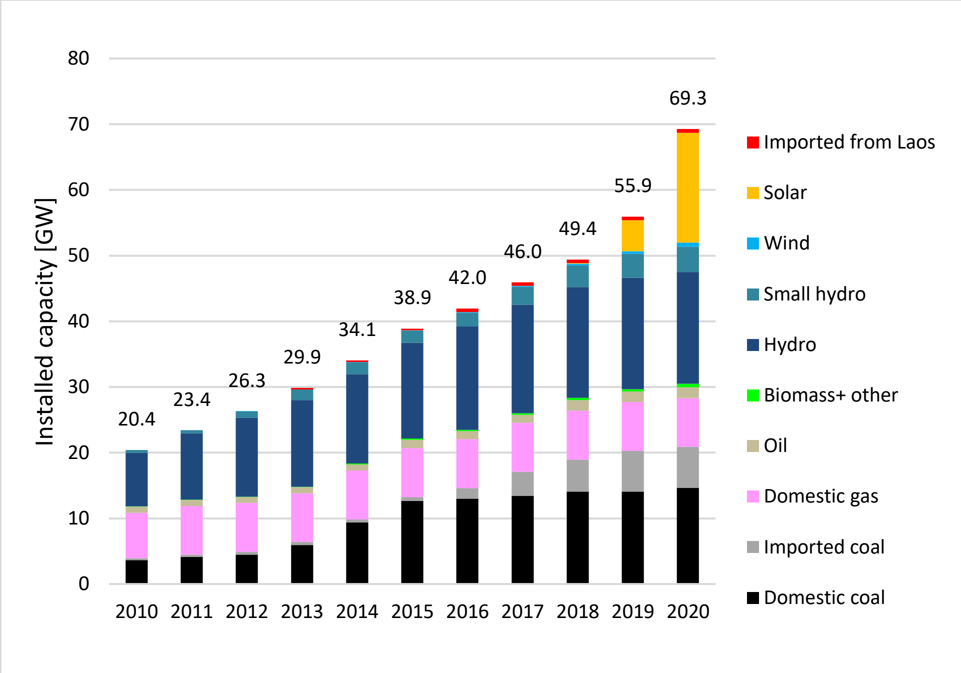


Figure 2: Historical installed capacity mix of Viet Nam power system (NLDC, 2021)

The raw reserve ratio[1] is 79% if wind and solar power are included and 34.3% if wind and solar power sources are not considered. In the period 2011-2020, the total installed capacity of power generation increased by 12.9%/year on average. Among the traditional power sources, coal-fired power is growing fastest at average rate of 18%/year, followed by hydropower capacity at 9.2%/year. Besides traditional sources, utility-scale solar power and rooftop solar power have increased with sudden growth in the years 2019-2020 due to mechanism encouraging the development of solar power through feed-in tariffs (FIT). From a negligible level at the beginning of 2018, solar power capacity (including rooftop solar power) has reached 4.7 GW by the end of 2019 and 16.7 GW by the end of 2020, of which 7.8 GW is rooftop solar power.

Electricity sector challenges

The rapid development, the large annual required investment capital, the impact of technological development, and the environmental effects associated with the electricity sector pose several challenges going forward. Seven main issues have been identified and are described briefly below.

- *The Vietnamese electricity demand is anticipated to continue to grow rapidly in the period from now to 2030 and beyond*. The document of

[1] Raw reserve ratio = (Total installed capacity/Peak load) - 1

the 13th Communist Party of Viet Nam Congress (2021) has projected a socio-economic development strategy in the period of 2021-2030 with an average GDP growth rate of 7%/year. According to that, Power Development Plan VIII (PDP8) forecasted in base case scenario: annual sale energy growth rates during the period 2021-2025 will be about 9.1%, and only decreasing slightly to 8% per year during the 2026-2030 period. With base case of power demand development, the total installed generation capacity in 2030 must grow to 138 GW, in which renewable energy (including hydro) capacity occupies over 47%, specifically solar and wind power capacity occupy over 26%. Growth of this magnitude poses major challenges, including: securing adequate investment capital, construction of electricity generation sources, transmission and distribution grids and other related infrastructure, modernising operation of the electricity system, ensuring cost-effective and efficient use of electricity, and ensuring human resource development.

- *Shift to net imports of fuels required for electricity production as domestic sources become exhausted*. According to PDP8, Viet Nam will have exploited most of its economic and technical potential of large and medium-sized hydro plants. Domestic coal mining in the future is estimated to be able to supply only 13 GW of existing coal-fired capacity. In 2019, Viet Nam imported large amounts of coal for electricity production (about 5 million tons). Domestic gas extraction in Southeast and Southwest areas will be reduced quickly in the period 2021-2025. Viet Nam will have to import LNG to compensate for this reduction for existing CCGTs in the Southeast, and to purchase gas from Malaysia for Ca Mau CCGTs from 2020. In the future, there will be 7 GW of new CCGTs using Blue Whale (CVX) gas and Block B gas will come into operation in 2025-2026. In 2020, Viet Nam discovered a new gas field (Ken Bau gas in Centre Central) which can supply gas for about 3-5 GW new CCGTs in the Centre. Besides that, according to PDP8, Viet Nam still has to import LNG to supply for about 12-17 GW of new CCGTs up to 2030. Limited primary energy resources or the depletion thereof, e.g., hydropower, domestic coal, and gas, represents a huge challenge for the electricity sector, as it raises issues related to energy security, ensuring a safe and reliable power supply, as well as how to finance the large costs for imported fuels and related infrastructure.
- *Vietnam's electricity system develops rapidly but has some weaknesses*. The electricity infrastructure requires reinforcement, as several subsystems are outdated.

    - There are some thermal power plants with long remaining lifetimes that have outdated equipment and low efficiencies. Some thermal power plants operate unstably and often have contingency outage, especially thermal power plants in the North. Thermal power plants are not very flexible, due to high start-up cost and high stable minimum generation requirement.
    - Although the power system has high total installed capacity with high raw reserve rate, electricity demand still must be shedded at times of peak demand. This is mainly caused by limitations of the transmission grid. Especially in 2021, the South was heavily affected by the COVID-19 pandemic while the North was less affected. This caused the Northern power load to grow faster than in the South. Therefore, in the coming years, the North will be at risk of power shortage, while thermal power plants in South are under-utilized.
    - The transmission grid can still become overloaded and power quality is not high (e.g., overload occurs in the transmission grid of Ha Noi and Ho Chi Minh city areas, over voltages still occur in the 500 kV inter-regional transmission line).
    - The systems for protection, automation, and communication are not synchronised, and the automatic control functions do not work smoothly. Smart grid implementation is still in a testing stage.
- *Strong growth in renewable energy deployment posed large challenges*: By the end of 2021, the Vietnamese power system has about 4.6 GW of wind power and 16.9 GW of solar power. These variable renewable energy sources account for 28% of the whole system's installed capacity, and cover about half of the system’s peak demand. This strong development of variable renewable energy (VRE) caused many difficulties for system operation*:*
    - Wind and solar power production are non-dispatchable, operating a power system that incorporates a large proportion of solar and wind power sources requires investment in reserve generation capacity, sources of electricity storage, improved weather and meteorological forecasting, and improved grid connection.
    - Renewable energy sources are developing on a large scale in the South and Central regions, while power demand will grow most in the Northern regions. The construction of transmission

lines faces many difficulties due to limited land, passing through many provinces, forest areas and ecological conservation areas. Realising transmission expansion is a big challenge for scaling up renewable energy capacity.

  - The curtailment of renewable energy at specific times to ensure reliable operation and flexibility for the system causes disagreement from investors and social organizations.
  - Existing coal thermal power plants use old technology with very high start-up cost and high stable minimum capacity requirement. PVN's take-or-pay gas contracts with field owners have put pressure on gas power plants to consume gas by contract. This hinders the integrating of high penetration of VRE.
  - The development of VRE sources requires increasing reserve capacity in the power system. However, the ancillary service market has not been properly developed. Power sources and loads are not encouraged to participate and provide ancillary services. This makes it difficult to safely operate the power system.

- *Environmental and climate change issues increasingly put pressure on the electricity sector*. Up to 2030, CO_2 emissions in the power sector account for 70% of total emissions from the energy sector and 60% of total national CO_2 emissions. Vietnam's international commitment to reduce CO_2 emissions in NDC2020 is a voluntary reduction of 9% and a reduction of up to 27% with international support compared to the business-as-usual scenario. At the COP26 conference, the Prime Minister announced that Viet Nam has a goal of net zero CO_2 emissions by 2050. The demand for investments in power sources in the coming period is quite large because the electricity demand is forecasted to have a high growth rate. At the same time, the Vietnamese power system must meet emission reduction requirements and have reasonable electricity prices to facilitate the socioeconomic development.
- *Difficulties in mobilizing investment capital for the power sector*: the Vietnamese national economy and overall infrastructure are still under development, and it may therefore be difficult to allocate the required resources for the development of the power sector. The Vietnamese transport infrastructure, infrastructure that supports industry, and construction capacity are also all in the development stage. Except for some types of power sources with FIT pricing mechanism to encourage development, Vietnam's electricity prices are not particularly attractive to investors, leading to difficulties in mobilizing financing for power

projects in both the public and the private sector, as well as the foreign investment sector.

- *Development of a competitive electricity market and the liberalisation of the electricity sector are being promoted*. Accordingly, the state will only retain power plants for strategic purposes (for example, large hydroelectric power plants, multi-purpose services such as Hoa Binh HPP, Son La HPP), while other power plants will gradually be privatised. The government encourages both foreign and domestic actors to invest in building electricity generation capacity. The state will only hold monopolies regarding the interregional backbone transmission grid. The policy of expanding ownership in the electricity sector development has created investment opportunities for many sectors. This is expected to benefit the development of the power system, but requires adequate market design and transitional arrangements.

2 Modelling framework

The TIMES model

TIMES model generator: principles and coverage

The TIMES (The Integrated MARKAL-EFOM System) model generator is developed as part of the IEA-ETSAP's methodology for energy scenarios to conduct in-depth energy and environmental analyses. The complete source code is published under the open GPL3 license and can be retrieved free of charge from GitHub (https://github.com/etsap-TIMES/TIMES_model). The TIMES model generator combines two different, and complementary, approaches to modelling energy: a technical engineering approach and an economic approach (Loulou, Goldstein, Kanudia, Lettila, & Remme, 2016). Currently, 21 countries, the EU and a private sector sponsor are participating to ensure the continual advancement of the methodology.

Moreover, TIMES is an economic model for analyses of national energy systems, which provides a technology-rich basis for estimating energy dynamics over a long-term horizon. It is usually applied to the analysis of the entire energy sector. The reference case estimates of end-use energy service demands (e.g., car road travel; residential lighting; steam heat requirements in the paper industry; etc.) are provided by the user for each region. In addition, the user provides estimates of the existing stock of energy equipment in all sectors, and the characteristics of available future technologies, as well as present and future sources of primary energy supply and their potentials.
Using these as inputs, the TIMES model aims to supply energy services at minimum global cost by simultaneously optimizing technology investment and operation.

On the other hand, TIMES presents some modelling limitations, including assumptions on perfect foresight, perfect market conditions and modelling from the point of view of a central planner with perfect information on all events on the time horizon.

TIMES-Vietnam

The TIMES-Vietnam energy system model has been developed under the World Bank funded project "Getting Vietnam on a Low-Carbon Energy Path to Achieve NDC Target" (DWG, 2018) which supports MOIT in developing cost-effective low-carbon energy mitigation options and pathways both on the demand and supply sides to achieve the NDC target. It has been developed along with building local expertise to effectively steward and apply the methodology on a long-term basis. The TIMES-Vietnam model has been further adapted to support the scenario analysis of the EOR21.

The TIMES-Vietnam model covers all parts of the energy system, from primary energy resources to power plants and other fuel processing plants, ultimately to various demand devices in all five demand sectors[2].

Primary energy, in the form of domestic and imported fossil fuels and electricity, and a variety of domestic renewable energy sources are available to meet the energy demands of the country. Power plants and fuel processing plants convert the primary energy sources into final energy carriers, such as electricity, oil products and natural gas, which are used in the demand sectors. There are both existing and potential future plants grouped by fuel and technology type, which are characterized by their existing capacity or investment cost, operating costs, efficiency, and other techno-economic parameters. The final energy carriers are consumed in demand-specific end-use devices (e.g. electricity is used in residential lamps for providing lighting), that are used to satisfy the demands for energy services in that sector.

The model contains five demand sectors: Agriculture, Commercial, Industry, Residential and Transportation. Each demand sector is characterized by a specific set of end-use devices that deliver end-use services (such as lighting, cooling, cooking, industrial process heat, motor drive, passenger, and freight travel). These existing and potential new end-use technologies are characterized by their existing capacity or investment cost, operating costs, efficiency, and other performance parameters. The demands for energy services are determined by projecting the base year energy demands, which are derived from the energy balance 2014 (IE, 2017) as part of the calibration process, in accordance with sector-specific drivers, such as GDP growth, GDP per capita growth, industrial production projections, space cooling growth expectations, etc.

[2] For further information about the TIMES – Vietnam model see separate “TIMES Data Report”.

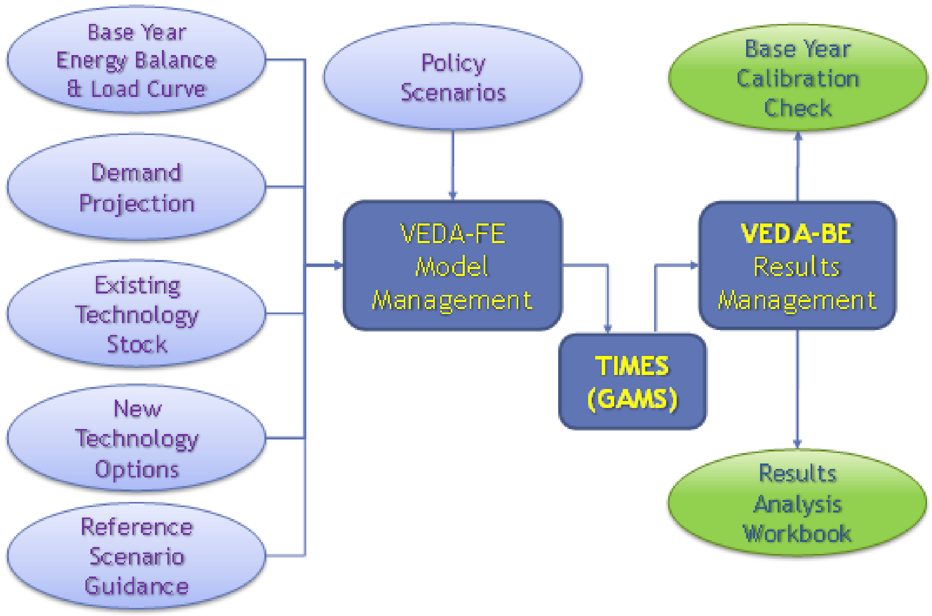


Figure 3: Modelling framework for TIMES-Vietnam

The base year 2014 is chosen due to solid data availability and consistency with other NDC assignments, which are being implemented across several ministries (MOIT, MONRE, MOT etc.). The base year energy service demands in 2014 are extrapolated up to 2050 with following assumptions and expert judgements for all main scenarios:

- GDP increases at 7% in 2016, decrease to 5.93% in 2020, and is projected to be 6.77% in 2025, 6.42% in 2030, 6.00% in 2035, 5.57% in 2040, 5.49% in 2045, 5.25% in 2050 (IE 2021)
- Population and urbanization as in GSO's projections to 2050 (MPI 2021)
- Industrial demands grow as in approved development plans for several industrial subsectors[3]
- Residential demands grow in line with the increases in population and urbanization
- Agricultural, and commercial and transport demands grow in line with the GDP growth rate
- Transport demand projections for each transport are from the Ministry of Transportation

TIMES-Vietnam is structured with twelve (12) time slices: three seasons (Wet, Intermediate and Dry) and four sub-divisions of the day (day, morning peak, evening peak and night).

[3] Collected from various official documents for approval of sectoral development plans.

Owing to the nature of the availability of resource supplies and the long-distance transmission lines in Vietnam, three transmission regions are identified in TIMES-Vietnam: North, Central and South for domestic resources (including renewables), refineries, and power plants. The existing capacity of the transmission lines between the regions are reflected in the model, along with the cost for expanding the infrastructure in the future. A fourth consumption region (Vietnam) is used to depict the national demand for the five (5) end-use sectors. The three transmission regions each deliver their outputs (power and fuels) to the national consumption region. Consumption centre constraints have been set on the transmission lines connecting each transmission region to the consumption region to reflect the limitations of, e.g., power plants in the North delivering power to the South.

The Balmorel model

The Vietnamese power system analyses are carried out with the Balmorel model. Like TIMES, Balmorel is a least-cost optimization model, but with a focus on the power (and district heating) sector. The model optimizes both the dispatch of generation units and the capacities of future investments in generation and transmission. Balmorel uses a detailed technical representation of the existing power system, as well as a catalogue of well-defined investment options for generation and transmission. All existing and committed generation plants are represented on an individual basis. Investment options are available as generic technologies. Among other, these are coal and gas turbines, wind turbines, solar cells, biomass plants, small hydro plants, and nuclear reactors. Investment potential is also available for interconnector capacity between Vietnamese regions. Development of interconnection with neighbours is not subject to optimization.

The Balmorel model can either be run with a full hourly time granularity or can implement time aggregation to reduce complexity and thereby computation time in order to allow for investment optimizations. Dispatch optimizations with fixed investments in future capacities (based on a previous investment optimization run) can then be made to analyse the hour-by-hour balancing of power system when large shares of variable renewable energy (VRE) are integrated in the power system.

Balmorel - Viet Nam

The Vietnamese Balmorel model contains input data on the Vietnamese electricity system on a regional level: the map in Figure 4 illustrates the existing (2020) interconnected power system in Vietnam. The country is represented as seven transmission regions, for which the electricity balance between supply and demand is made. The transmission regions are connected by transmission lines with fixed capacity. In total, eight lines connect the transmission regions, allowing for flow exchange between regions to meet the electricity balance.

In addition, three transmission lines connect individual power plants in China, and Laos to the Vietnamese grid. Plants in neighbouring countries which deliver power to Viet Nam are limited to existing and planned capacities and optimized interconnections between neighbouring power grids are not included.

As mentioned, the Balmorel model can be run with full hourly resolution or with aggregated time steps to save computational time. The current analysis represents each year by 336 time-slices per year, utilizing 24 aggregated seasons, representing half monthly periods each. Each of these seasons is modelled with 14 time-steps, which are aggregated in a logical way, grouping all hours of the week with a similar character (e.g, peak load, solar peak, low demand in weekends and nights etc.). This time aggregation is evaluated to have a good representation of a year and, at the same time, optimizing the amount of computational time needed to simulate a year.

Lastly, it is worth noting that Balmorel is a free-of-charge, open-source model and has been adapted and continuously updated for Viet Nam during a series of activities in the last 7 years. For more information about the model and examples for published studies, see (Ea, 2022). For a simplified online demonstration model, see (Danish Energy Agency, 2018).

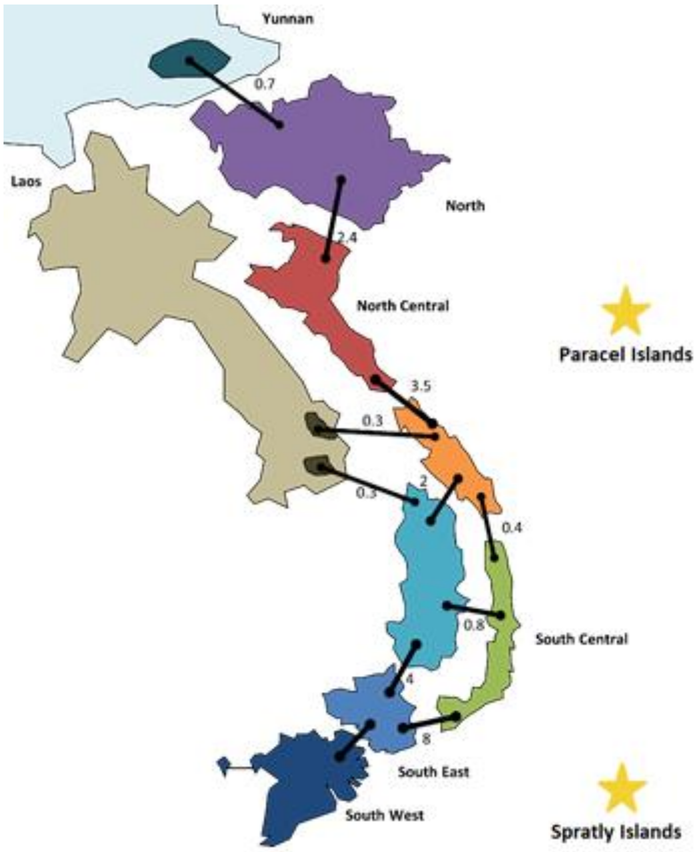


Figure 4. Transmission regions of Vietnam, connected neighbouring power plants and the current interconnectors in GW (2020)

The PSS/E model

The model PSS/E (Power System Simulator for Engineering) belongs to Power Technology Inc Company of Siemens Group. It is a program to simulate, analyse and optimize operational features of the power system, as well as power system planning.

The PSS/E model is widely used in Viet Nam for making short-term operation and long-term grid planning. Its main functions in grid planning are load flow, short circuit calculation, P-V curve and Q-V curve analysis, dynamic stability simulation. Additionally, N-1, N-2 criteria of the grid can be checked by using PSS/E simulation to analyse where these criteria are violated.
The PSS/E model was first used in National Load Dispatching Center (NLDC-A0) in early 1990s. Then, Institute of Energy (under EVN at that time) used PSS/E for grid design of National Power Development Plan (PDP) 4 (1995), PDP5 (2000), PDP6 (2005), PDP7 (2010) and PDP7 Revised (2015).
Now, NLDC (A0) and its subsidiary (Regional Load Dispatching Center – A1,2,3) are using PSS/E V33-34 for making their operation planning: Weekly, Monthly

and Yearly Planning. The version of PSS/E used in this study was used for Long-term Grid Planning in PDP8.

PSS/E - Vietnam

A detailed model of the Vietnamese power grid has been used to test grid related assumptions in the Balmorel power system analyses. The 500 kV and 220 kV national power grids for the years 2025 and 2035 are represented in the model, the 110 kV and lower voltage level power grid will be equivalent to the 220 kV nodes. The model has around 921 nodes and 1200 branches of lines for the system in 2035, including all plants (detailed by machines), loads, trans-formers, shunts, FACTSs, branches of lines.

In this study, the PSS/E model is harmonized with Balmorel results such as generation capacity and demand projections. For selected critical hours (snapshots) in the years 2025 and 2035, the Balmorel generation dispatch mix was modelled in PSS/E to compute the load flow of the power system. Over- and undervoltage on nodes and overloaded transmission lines was identified, in both normal operation mode (N-0) and in contingency mode (N-1) to assess breach of safe operation of the grid. If there is an overvoltage or undervoltage or power flow is above the nominal, the solution such as building new/renovate transmission lines, substations or installing compensation resistance/FACTS devices will be proposed to solve the problem.

There are around 8760 hours of generation dispatching mix in one year, corresponding to 8760-time steps of load (with approximate hourly accuracy). Therefore, in theory, it would be necessary to observe 8760 hours of power grid simulations in a year to test the ability of the grid to respond to generation dispatching and load at the same time. However, not all 8760 grid operation modes are critical. In the grid simulation of the planning problem, it is often only some of most critical operation modes that are interesting to reduce the calculated volume. If the most critical operation modes are satisfied, the grid can respond well to the remaining operation cases.
The interesting operation snapshots for the simulation of the load flow in the power system are chosen for BSL scenario as follow:

- Highest generation (HG)
- Lowest generation (LG)
- Highest residual demand (HRD)
- Lowest residual demand (LRD)
- Maximum total interconnected transmission capacity (HF)
- Minimum total interconnected transmission capacity (LF)
- Highest wind and solar Curtailment (HC)

Combined modelling suite and soft linking

Combining the three energy system models, TIMES, Balmorel and PSS/E allows for taking advantage of their complementary strengths. Table 1 summarizes the main purpose and the key characteristics of the three models.
As the TIMES model considers the largest scope - modelling all energy sectors, it is ideally suited to analyse allocations of resources or emissions across sectors. It can also model electrification of e.g., the industry and transport sector.

The Balmorel model optimizes the power sector with increased temporal and geographical resolution, making it the best model to analyse developments of power generation and transmission capacities in the future, the impact of system flexibility such as demand response and storages and the integration of variable renewable energy.

Finally, the PSS/E model examines the power grid in high detail, looking at load flow and voltages and testing the N-1 criteria to assess the robustness of the grid.

	TIMES	Balmorel	PSS/E
Main purpose	Cost-optimal **allocations across sectors** of: • Resources (e.g., biofuels) • Carbon emissions • Electrification measures	Cost-optimized **power system build-out** and **dispatch**: • Power generation and transmission system • Demand response and storages • Integration of VRE	Calculation of the **load flow of the power grid system**, checking the voltage and load of all lines. Testing of N-1 situations.
Sectors covered	**The supply sector and all 6 energy sectors**: Agriculture, Commercial, Industry, Power, Residential, Transport	**Power sector** only, providing much more detailed representation than TIMES	**Power sector** only, providing even more detail on the electricity grid
Temporal resolution	**12 timesteps**: 3 seasons x 4 slices	**336 timesteps:** 24 seasons x 14 slices	**7 timesteps:** 7 snapshots of one hour
Geographic resolution	**1 main region:** Vietnam **3 sub-regions:** North, Central, South	**7 regions:** North, North Central, Centre Central, South Central, Highlands, South East, South West	**921 nodes**: voltage level 500 kV, and 220 kV.
Foresight	Full foresight in modelling period	Myopic – one year at a time	Myopic – one snapshot at a time

Table 1: Main purpose and key characteristics of the three models in the modelling suite for EOR 2021: TIMES, Balmorel and PSS/E

To assure consistent scenarios across the three models, the input data is aligned (see Chapter 3). Additionally, the three models are soft linked, meaning that the results from one model are implemented as input to the next. Figure 5 illustrates the soft links between the models. Several iterations were made to arrive at the final scenario results presented in this report.

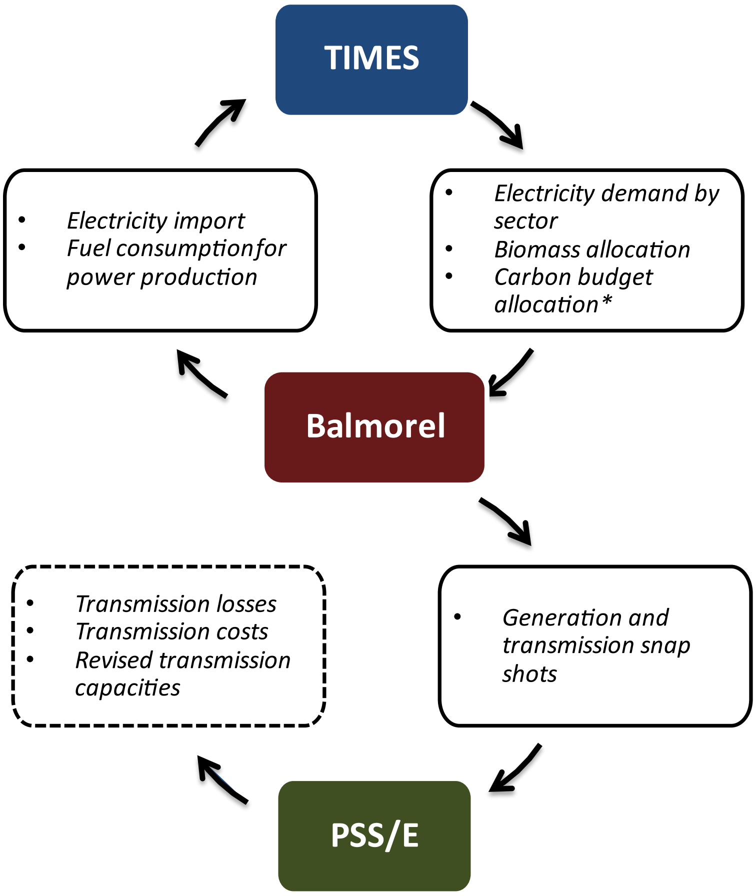


Figure 5: Modelling suite for EOR 2021 and soft links.

Linking TIMES and Balmorel

Concerning the soft linking between TIMES and Balmorel, TIMES provides input to Balmorel on the allocation of the domestic biomass resource for the power sector and on the allocation of the carbon emissions' budget for the power sector (in one scenario only). Both constraints are used as upper bounds to the Balmorel model. Additionally, the TIMES model determines the total power demand, including the results of electrification of the other sectors, which is then utilized in the Balmorel model.

In the other direction, Balmorel provides input on the fuel consumption of the power sector to TIMES, which is used as an upper bound on the fuel consumption in TIMES. Balmorel also provides an upper bound on the possible amount of electricity import from neighbouring countries as well as the price of importing. The linking process is performed once per scenario.

Linking Balmorel and PSS/E

The Balmorel model is soft-linked to the PSS/E model by determining some potentially critical hours in the year (snapshots) for the transmission grid. 7 critical hours are selected based on generation, residual demand, flow, and curtailment. The dispatch per generator and flow per transmission line for those snapshots are then provided to the PSS/E model which simulates the grid robustness under those circumstances.

Insights derived from PSS/E results on transmission losses, revised transmission capacities and transmission costs for grid reinforcements can then be cycled back to the Balmorel model but have not been fed back for the results shown in this report.

3 Key input data

Data flow in the modelling framework

The data requirements for the three models in the modelling suite are extensive.

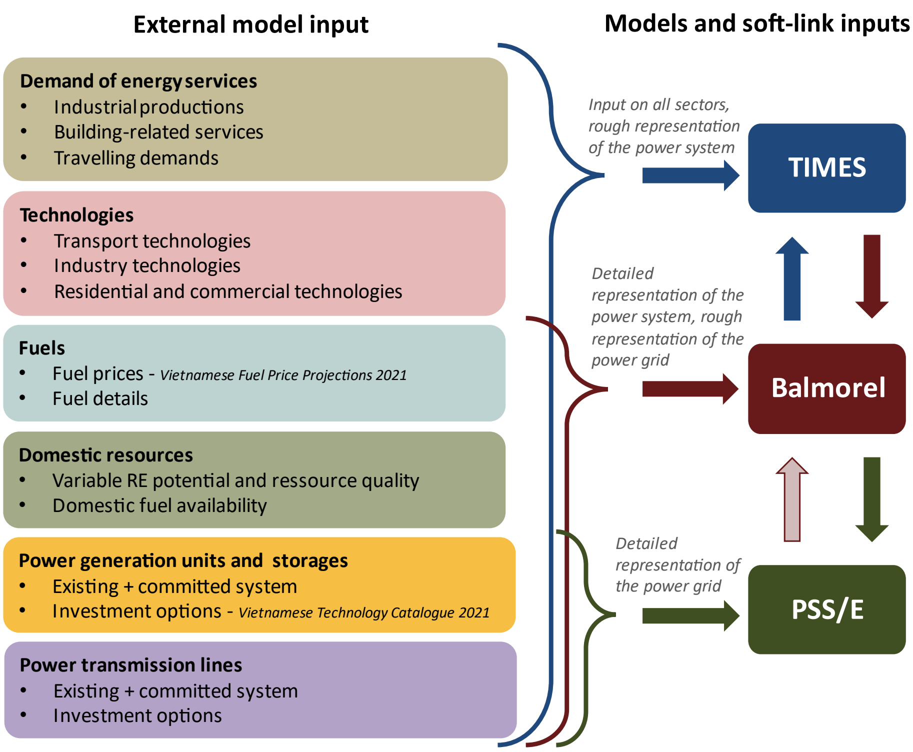


Figure 6: Key input data to the three models, TIMES, Balmorel and PSS/E. Soft linking input is seen in detail in Figure 5

External model input to TIMES and Balmorel

Demands for energy services

The primary demand drivers include GDP growth, population growth, and the number of persons per household. As the year 2020 had a very low growth rate due to COVID-19 and that the TIMES-model is only run for every five years, the GDP growth rate has been calibrated to fit with the realised demands. The applied GDP growth rate is seen in Figure 7 and the population growth with expected persons per household can be seen in Figure 8.

There are secondary drivers for each demand sector, such as the elasticity of energy use to GDP growth, industrial production projections, market penetration rates for space cooling, refrigeration, and electric appliances.

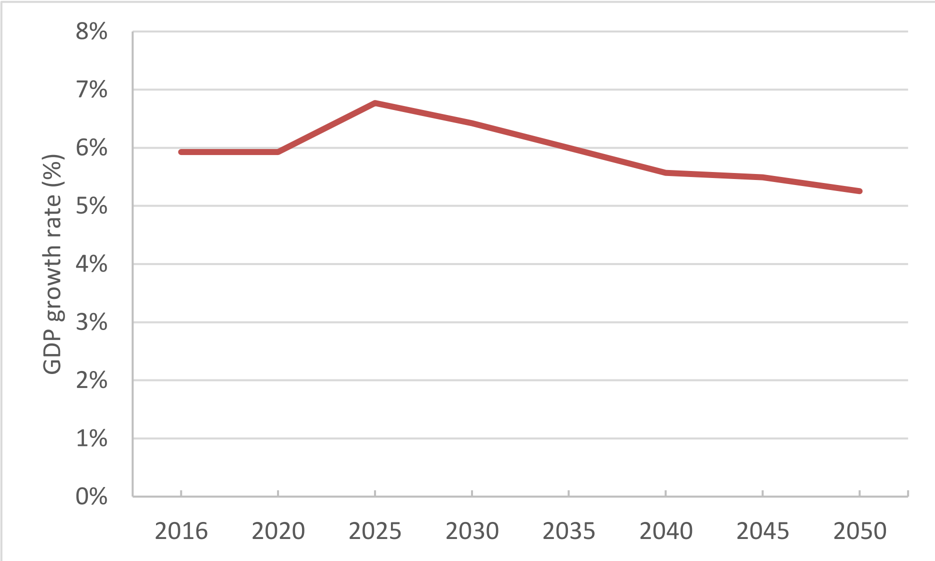


Figure 7: Applied GDP growth rate (real)

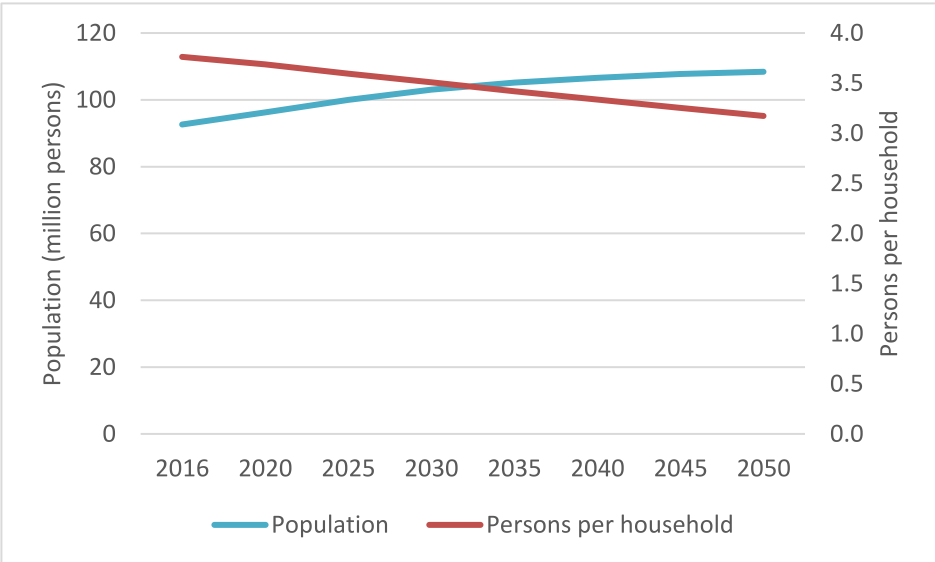


Figure 8: Expected population growth and persons per households

Due to the increase of GDP and population, the demand for industry, residential, commercial, and agricultural is projected to increase in period 2020 – 2050, see Figure 9. The demands are specified for each end use sector, which are specified on country level.

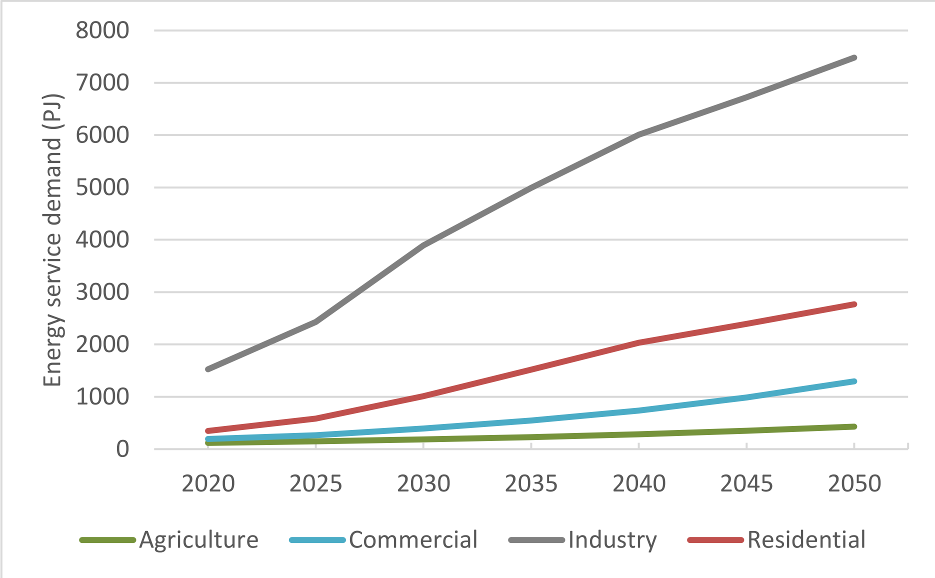


Figure 9: Energy service demand projection (PJ) (excluding transport sector)

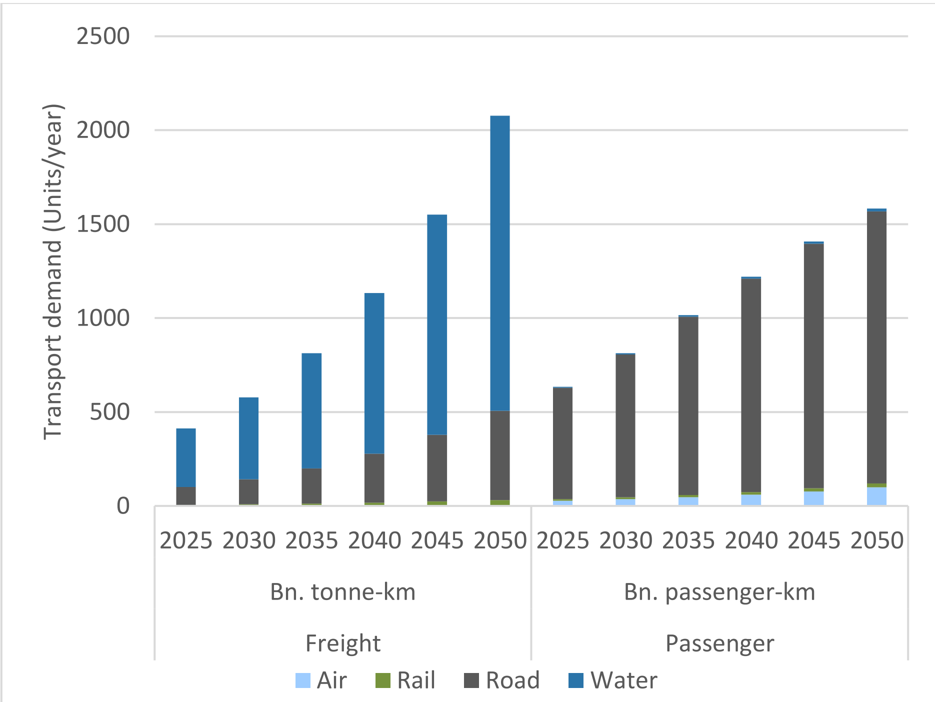


Figure 10: Freight and passenger transport demands. Source: Ministry of Transportation

Transport includes freight and passenger transport, which are divided into road, rail, water, and air transportation. The demand data for 2020 – 2050 are presented in Figure 10.

Domestic fuel potential

Coal and natural gas

Vietnam has large coal resources, however according to the coal exploitation plan up to 2050, the commercial domestic coal production will be about 45 million tons in 2025, about 53 million tons in 2030, about 55 million tons in 2035, plan for domestic coal exploitation after 2035 will be depend on the policy of Vietnam in Net zero commitment.

About domestic natural gas, the total domestic gas supply according to the base case exploitation plan is about 13 billion m^3 hydrocarbon gas in 2025, reduce to 12.4 billion m^3 in 2030 and 11.6 billion m^3 in 2035. Existing exploiting mine in Southeast and Southwest will reduce output in near future. Therefore, Vietnam has plan to import LNG to compensate gas for CCGTs in Southeast, and purchase gas from Malaysia to compensate gas for Ca Mau CCGTs (1500MW) in Southwest up to 2031. After year 2025, domestic gas from Block B mine and CVX mine can supply total about 7.7 billion m^3/year hydrocarbon gas for electricity production.

In 2020, Vietnam discovered a new gas field (Ken Bau gas in Center Central) can be supply annual about 3-5 billion m^3 hydrocarbon gas in Center, but now this mine is still in research period, not yet determine to develop and exploit, so EOR21 will calculate Ken Bau gas as candidate in model, model will choose whether to develop Ken Bau gas.

Biomass and waste

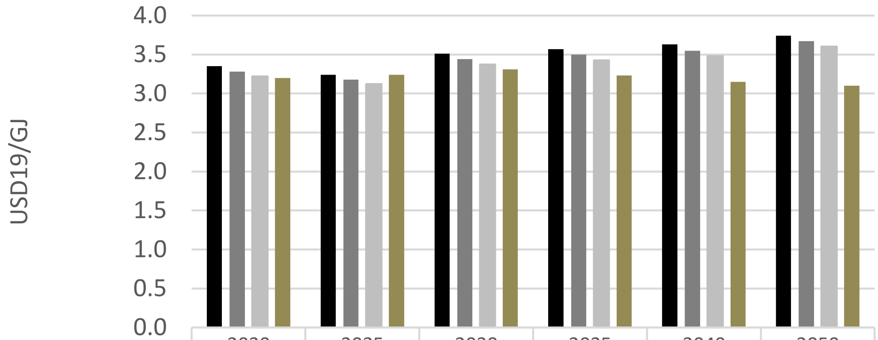
Total technical potential of biomass in Vietnam about 15000 kTOE/year, total technical potential of MSW about 1200 - 2000 kTOE/year. This technical potential will be model in TIMES. Annual fuel constraints for biomass types and MSW are inputs to the Balmorel model found from the optimization of all energy sectors in TIMES.

Fuel prices

As a net importer of fuel, Viet Nam is therefore directly exposed to international fuel prices. Thus, projections of future prices are an important input to least-cost optimization and analyses of the Vietnamese energy system.

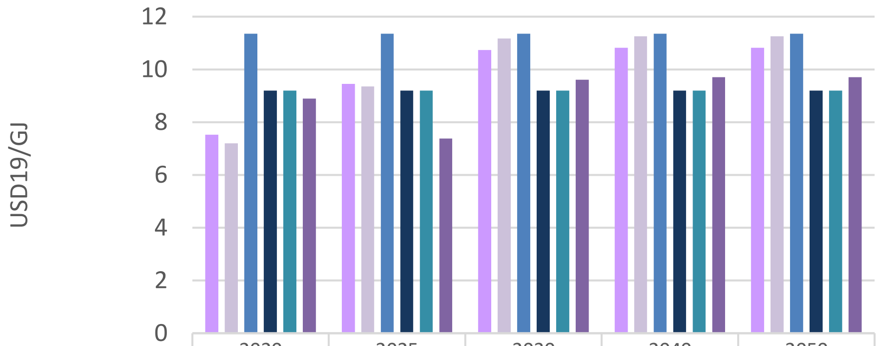
Figure 11-Figure 13 show historical fuel prices as well as the fuel price projections used in the models. The detailed study and methodology used for fuel prices and price projections is outlined in a separate report (EREA and DEA, 2021a).

For imported coal and LNG, transport cost add-ons - differentiated across regions - are added to the fuel prices to reflect, e.g., differences in distance to harbours. Fuel prices of all fuels, without add-ons, used in the Balmorel model are shown in Figure 11-Figure 13.



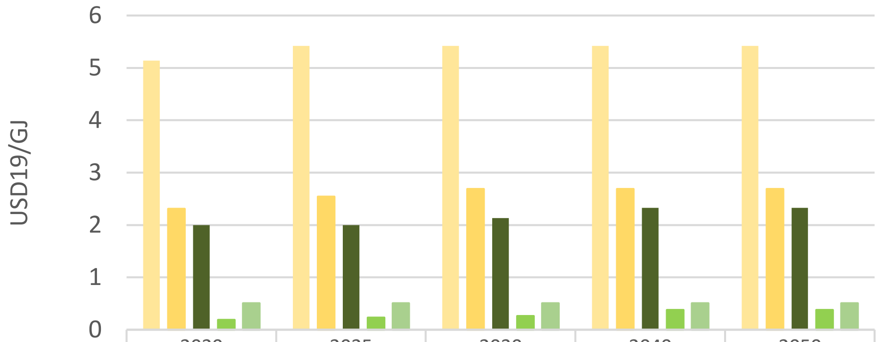
	2020	2025	2030	2035	2040	2050
Dom. Coal (4b-5)	3.35	3.24	3.51	3.57	3.63	3.74
Dom. Coal (6)	3.28	3.18	3.44	3.50	3.55	3.67
Dom. Coal (7)	3.22	3.12	3.37	3.43	3.48	3.60
Imp. Coal	3.20	3.24	3.31	3.23	3.15	3.10

Figure 11: Coal price projections in Vietnam. Different coal types are included where Coal 7 has the lowest caloric value and coal 6 is slightly higher quality and coal 4b-5 has the highest quality.



	2020	2025	2030	2040	2050
NG (South-East)	7.53	9.45	10.73	10.82	10.82
NG (South-West)	7.20	9.36	11.17	11.26	11.26
NG (Block B)	11.35	11.35	11.35	11.35	11.35
NG (CVX)	9.20	9.20	9.20	9.20	9.20
NG (Ken Bau)	9.20	9.20	9.20	9.20	9.20
LNG	8.90	7.38	9.61	9.71	9.71

Figure 12: Natural gas price projections in Vietnam.



	2020	2025	2030	2040	2050
Straw	5.14	5.42	5.42	5.42	5.42
Rice husk	2.31	2.54	2.69	2.69	2.69
Wood	2.00	2.00	2.13	2.33	2.33
Bagasse	0.19	0.23	0.26	0.38	0.38
Corn	0.51	0.51	0.51	0.51	0.51

Figure 13: Biomass price projections in Vietnam.

Investment options for the power sector

Power and storage capacity

In the Vietnamese technology catalogue (EREA and DEA, 2021b), international and Vietnamese investment costs for coal and natural gas-based generation plants, as well as wind and solar power, have been compared, along with the development of expected investment costs for 2020, 2030 and 2050. For more information, please refer to the Viet Nam Technology Catalogue for electricity generation and storage. The catalogue also contains information about hydro, tidal, wave, biomass, biogas, waste, geothermal, internal combustion engine, pumped hydro, nuclear, and electrochemical storage. In addition to investment costs, operation and maintenance costs (variable and fixed O&M), technology efficiencies, as well as many other technical parameters are described.

The techno-economic information from the Viet Nam Technology Catalogue for electricity and storage 2021 has been implemented in the modelling framework (both for Balmorel and TIMES). Additional technologies have been introduced as investment options in the model, e.g., Advanced Ultra Supercritical (AUSC) coal plants, low-power wind turbines and nuclear plants. Lastly, concrete investment options for pumped hydro have also been introduced. Small differences exist between the Technology Catalogue and the Balmorel modelling investment costs, as e.g., in the model input interest during construction is added based on 10% investment cost and the lifetime of the power plant.

With respect to solar PV power, land costs are also included in the investment costs. Although floating and rooftop PV does not occupy land and therefore there are no land-use costs, the capital cost will be higher than utility scale PV (about 20-30%). According to the survey, the investment cost of rooftop PV is lower than that of utility scale PV due to the absence of land use costs and grid connection costs. The investment rate of rooftop PV is slightly lower than that of utility-scale solar power, however due to the higher possibility of shading, the infrequent maintenance of a utility scale plant, and the higher DC/AC factor compared of utility scale compared to rooftop, the number of hours of generating maximum capacity converted to capacity of rooftop solar will be lower than that of utility scale solar (about 15-20% lower).

End-of-life processing costs of solar panel and chemical in battery are also added to the investment cost in the year of investment. The disposing cost of solar PV about 0.02 MUSD/MW up to 2030, after 2030 about 0.01 MUSD/MW (IRENA, 2016). The cost of disposal of lithium-ion batteries about 0.03 MUSD/MW up to 2030, after 2030 about 0.02 MUSD/MW (Battery University, 2017) (the data is in net present value, 2020).

Nuclear decommissioning costs is included in CAPEX, model will be added back-end of nuclear fuel cycle (spent fuel removal, disposal and storage) – 2.33 $/MWh in Variable O&M cost, and front-end of nuclear fuel cycle (mining, enrichment, conditioning) – 7$/MWh in fuel price of nuclear.

Technology type	Available (Year)	CAPEX incl. IDC (kUSD/MW)	Fixed O&M (kUSD/MW)	Variable O&M (USD/MWhel)	Efficiency (%)	Technical lifetime (Years)
Nuclear	**2030 - 2050**	6,367	74.18	5.13	40%	50
Coal subcritical	**2020 - 2029**	1,622	32.64	2.46	36%	30
	2030 - 2049	1,608	31.57	2.25	36%	30
	2050	1,568	30.50	2.14	36%	30
Coal supercritical	**2020 - 2029**	1,789	39.60	0.78	37%	30
	2030 - 2049	1,698	38.50	0.12	38%	30
	2050	1,674	37.20	0.12	39%	30
Coal ultra-supercritical	**2020 - 2029**	2,027	61.10	0.12	42%	30
	2030 - 2049	1,893	59.40	0.12	43%	30
	2050	1,880	57.50	0.11	44%	30
Coal AUSC	**2035 - 2049**	1,925	70.48	0.12	50%	30
	2050	1,800	72.80	0.11	50%	30
Coal CCS	**2020 - 2029**	4,307	83.10	4.00	29%	30
	2030 - 2049	3,885	80.60	3.25	30%	30
	2050	3,409	78.10	3.14	31%	30
CCGT	**2020 - 2029**	875	29.35	0.45	52%	25
	2030 - 2049	789	28.50	0.13	59%	25
	2050	778	27.60	0.12	60%	25
Small hydro	**2020 - 2029**	2,057	41.90	0.50	85%	50
	2030-2049	2,057	39.80	0.48	85%	50

	2050	2,057	37.30	0.45	85%	50
Wind (Low wind)	**2020 - 2024**	1,625	42.00	3.50	-	27
	2025 - 2029	1,506	42.00	3.50	-	27
	2030 - 2039	1,387	36.00	2.80	-	30
	2040 - 2049	1,279	36.00	2.80	-	30
	2050	1,170	28.00	2.30	-	30
Wind (Medium wind)	**2020 - 2024**	1,625	42.00	3.50	-	27
	2025 - 2029	1,506	42.00	3.50	-	27
	2030 - 2039	1,387	36.00	2.80	-	30
	2040 - 2049	1,279	36.00	2.80	-	30
	2050	1,170	28.00	2.30	-	30
Wind (High wind)	**2020 - 2024**	1,625	42.00	3.50	-	27
	2025 - 2029	1,506	42.00	3.50	-	27
	2030 - 2039	1,387	36.00	2.80	-	30
	2040 - 2049	1,279	36.00	2.80	-	30
	2050	1,170	28.00	2.30	-	30
Wind offshore*	**2020 - 2024**	3,702	70.00	5.00	-	25
	2025 - 2029	3,115	56.00	4.03	-	27.5
	2030 - 2039	2,459	42.00	3.05	-	30
	2040 - 2049	2,201	40.50	2.88	-	30
	2050	1,944	39.00	2.71	-	30
Solar PV (Utility scale)	**2020 - 2024**	1,004	15.50	-	-	35
	2025 - 2029	866	12.75	-	-	35
	2030 - 2039	725	10.00	-	-	40
	2040 - 2049	633	9.00	-	-	40
	2050	540	8.00	-	-	40
Solar PV (Rooftop)	**2020 - 2024**	1,027	14.80	-	-	35
	2025 - 2029	880	12.40	-	-	35
	2030 - 2039	730	10.00	-	-	40
	2040 - 2049	632	9.00	-	-	40
	2050	534	8.00	-	-	40
Solar PV (Floating)	**2020 - 2024**	1,169	15.50	-	-	35
	2025 - 2029	1,021	12.75	-	-	35
	2030 - 2039	841	10.00	-	-	40
	2040 - 2049	734	9.00	-	-	40
	2050	619	8.00	-	-	40
Geothermal	**2020 - 2029**	5,236	20.80	0.38	10%	30
	2030 - 2049	4,843	19.20	0.36	11%	30
	2050	4,424	17.60	0.33	12%	30
Biomass	**2020 - 2029**	1,990	49.50	3.16	31%	25
	2030 - 2049	1,831	45.50	2.91	31%	25
	2050	1,598	39.60	2.53	31%	25
MSW	**2020 - 2029**	6,404	253.40	25.10	28%	25
	2030 - 2049	5,947	233.70	24.31	29%	25
	2050	5,278	201.20	23.48	29%	25
Tidal	**2020 - 2029**	7,227	70.80	-	-	25
	2030 - 2049	6,714	62.50	-	-	25
	2050	6,335	35.70	-	-	30

*Table 2: Power generation technology investment options. Costs are in USD19. *Offshore wind costs are further differentiated over the specific sites modelled (average costs are shown in the table).*

	Available (Year)	Volume CAPEX incl. IDC (kUSD/MWh)	Inverter CAPEX incl. IDC (kUSD/MW)	Fixed O&M (kUSD/MW)	Variable O&M (USD/MWh)	Efficiency (%)	Technical lifetime (years)
Battery	**2020 - 2029**	270	590	0.62	2.30	91%	20
	2030 - 2049	160	270	0.31	2.07	92%	25
	2050	90	160	0.16	1.84	92%	30

Table 3: Battery investment options (disposal cost included). Costs are in USD19. The battery is a Li-ion battery. Battery investments can be independently optimized in storage volume (MWh) and inverter (=charging/discharging) capacity (MW).

	Region	Total CAPEX incl. IDC (kUSD/MWh)	Total CAPEX incl. IDC (kUSD/MW)	Maximum Turbine/Pump capacity (MW)	Maximum Reservoir capacity (MWh)	Volume to output ratio MWh/ MW
Moc Chau PSPP	**North**	92	736	900	7,129	8
Phu Yen East PSPP	**North**	62	930	1,200	17,518	15
Phu Yen West PSPP	**North**	105	945	1,000	8,502	9
Chau Thon PSPP	**North Central**	106	954	1,000	8,502	9
Don Duong PSPP	**Highland**	107	963	1,200	10,479	9
Ninh Son PSPP	**Highland**	98	882	1,200	10,390	9
Ham Thuan Bac PSPP	**South Central**	101	909	1,200	10,390	9
Bac Ai PSPP	**South Central**	97	776	1,200	10,104	8
Phuoc Hoa PSPP	**South Central**	99	840	1200	10250	8

Table 4: Specific pumped hydro projects. Pumped hydro project can only be invested in with a fixed ratio between storage volume (MWh) and pump/turbine capacity (MW). Ratio indicated in the table per project. Efficiency is assumed 80%. The costs indicated are the total investment cost for the full pumped hydro system including storage volume, pump and turbine. The two CAPEX columns indicate this total cost per MWh storage on the one hand and per MW pump/turbine capacity. This is different from the battery table CAPEX costs

Transmission capacity

The model is also able to optimize the transmission capacity between different regions. The investment rate of the transmission lines is taken from the PDP8. Investment costs for each of the transmission line ($/MW/km) are as follows:

- 500 kV line: 600 $/MW/km
- 800 kV HVDC line from Center Central to North (600 km): 570-865 $/MW/km (depending on transmitted capacity 3 GW-6 GW)
- 800 kV HVDC line from South Central to North (1200 km): 480-590 $/MW/km (depending on transmitted capacity 3 GW-6 GW)

The investment cost estimates are based on the distance between regions, which are displayed in Table 5. No limitations are placed on the size of investments in transmission.

	Connection Voltage (kV)	Length (km)	Investment cost (kUSD/MW)
North - North Central (1-2)	500	330	210
North Central - Centre Central (2-3)	500	450	286
Centre Central - Highland (3-4)	500	200	127
Centre Central - South Central (4-5)	500	420	265
Highland - South (4-6)	500	300	242
South Central - South (5-6)	500	250	159
Highland - South Central (4-5)	500	300	191
North – Centre Central (1-3)	+/-800	600	342
North – South Central (1-5)	+/-800	1200	648

Table 5: Voltage levels, lengths, and investment costs for each transmission line.

CO_2-neutral technologies and potentials

Utility-scale solar PV

The total solar PV potential available in Balmorel sums to 964 GW. This potential covers utility scale solar (838 GW), rooftop solar (48 GW) and floating solar (77 GW). More detailed description is given in the following sections.

The total technical potential of utility-scale PV is determined in PDP8 about 838 GW, though up until 2030, the economic potential of 254 GW (as calculated in the PDP8) is used which is linearly increased to the full technical potential between 2030 and 2050. Utility scale solar PV is modelled for each of the 64 provinces. The resulting potentials per region are shown in Figure 14. Investments in utility scale PV include land costs and retirement costs.

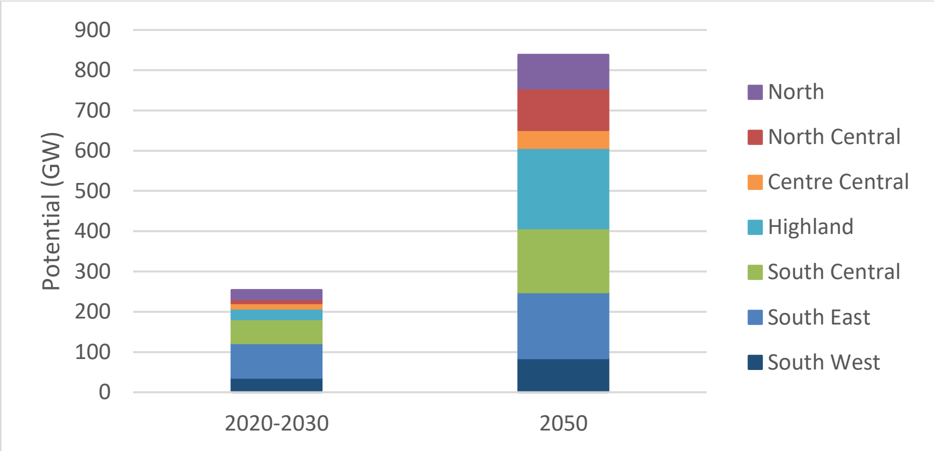


Figure 14: Solar PV potential implemented in Balmorel. Potential increases linearly between 2030 and 2050

Rooftop and floating PV

According to PDP8, the total potential of rooftop solar power nationwide is up to 48 GW, of which 22 GW is in the South region. Total technical potential of floating PV is about 77 GW according to PDP8.

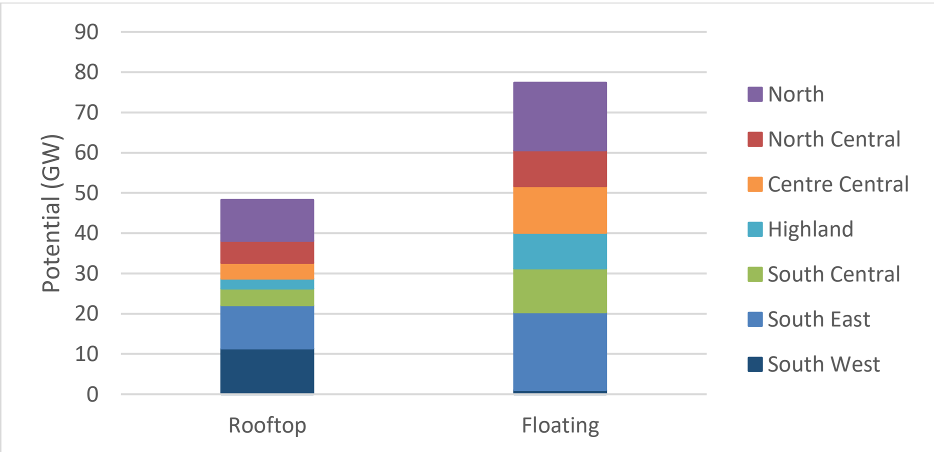


Figure 15: Solar PV potential implemented in Balmorel for Rooftop and Floating PV. Potential is constant over the years.

Onshore wind

An hourly wind profile for a normal year has been computed for low (4.5 – 5.5 m/s), medium (5.5 – 6 m/s) and high (6+ m/s) wind speeds for each of the seven regions based on hourly wind speed data provided by Danish Technical University Department for Wind Power. Corresponding potentials are shown in Figure 16.

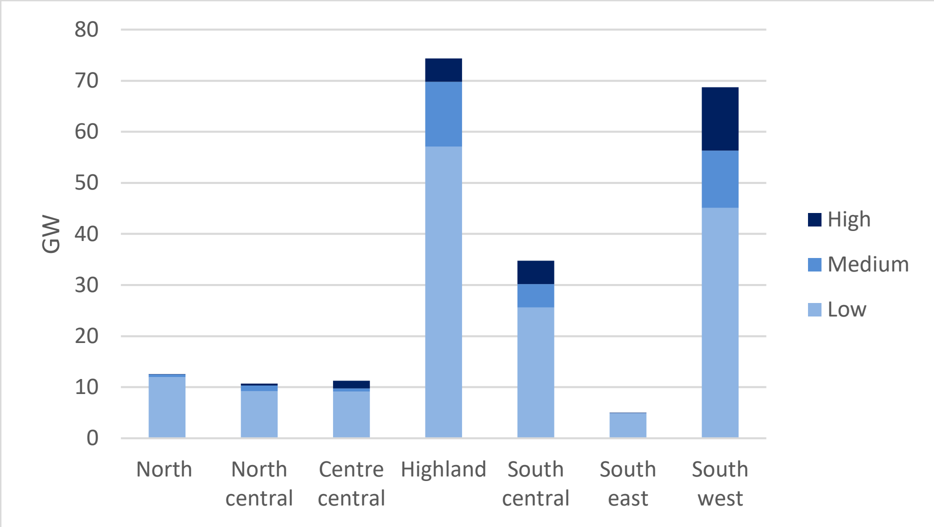


Figure 16: Onshore wind potentials by wind speed and region.

Offshore wind

In a GIS study (C2Wind, 2020), C2Wind ranked 42 potential regions of offshore wind and the best regions were selected and clustered as in the Figure 17. This study only implements superior offshore regions, thus the white regions shown in the figure are not included in the model. Total technical potential of offshore wind sums to about 120 GW and is distributed by regions as shown in Figure 18.

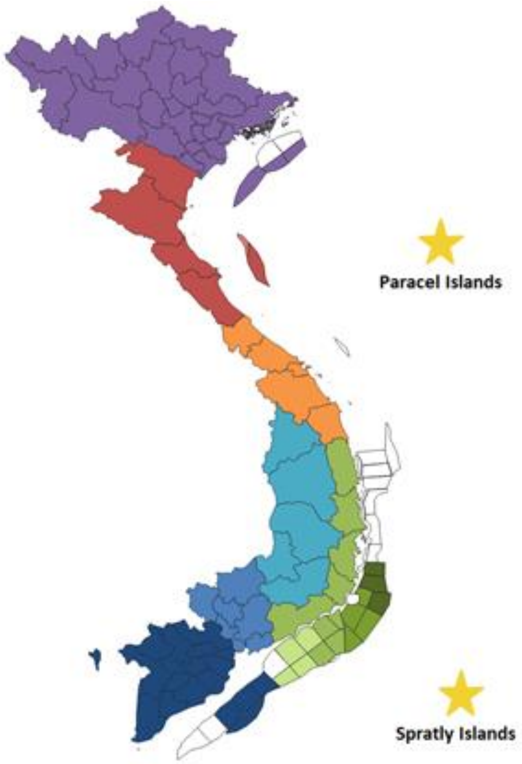


Figure 17: Offshore wind technical potential regions

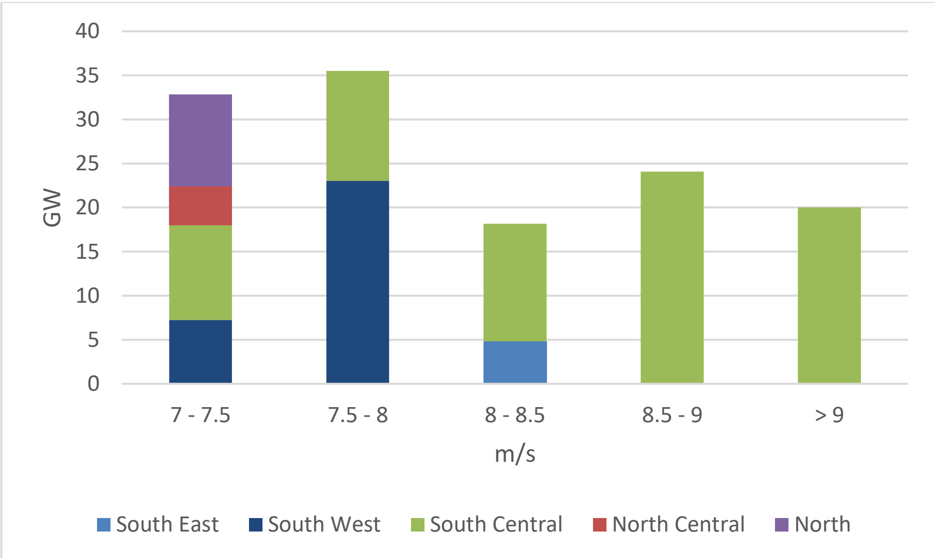


Figure 18: Offshore wind technical potential by wind speeds

Nearshore wind

Several nearshore projects are registered for construction in the South West region. These projects are located in areas with lower seabed depth (less than 20 m) and not far from shore (less than 50 km), with wind speeds around 6.5 m/s. The investment costs range between those for onshore and offshore wind projects. These projects can be classified into the high wind power type but have higher investment costs (can be considered as nearshore wind). The total registered construction potential of these nearshore wind projects in the South West region is up to 14 GW, in the North and North Central regions there are roughly 0.7 GW and 1.7 GW potentials, respectively.

Small run-of-river hydropower

The model has the option to invest in additional hydro capacity. The potential for additional small run-of-river hydro is 11.3 GW, distributed across regions as shown in Figure 19. Full load hours for all run-of-river hydro are assumed to be 2950.

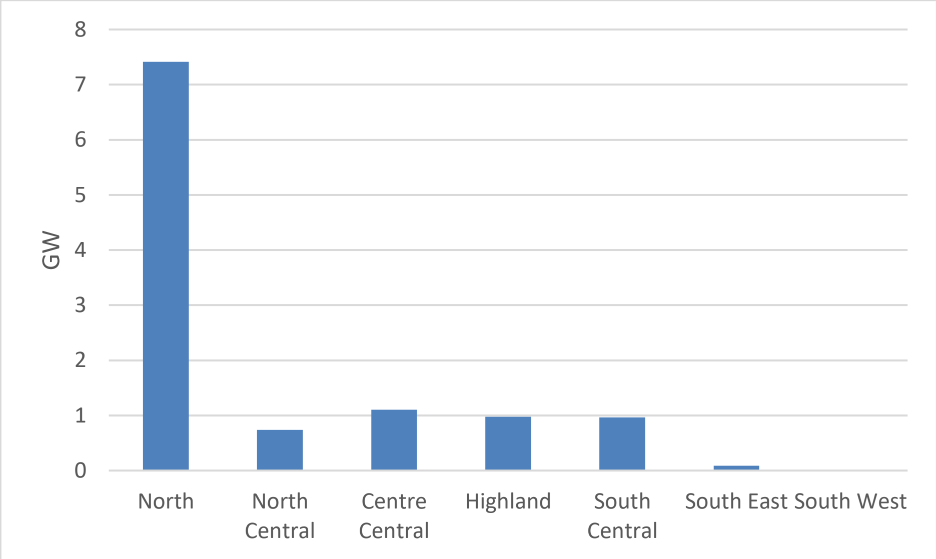


Figure 19: Additional run-of-river hydro potential.

Nuclear power

According to Decision No 906/QD-TTg, 17/6/2010, Approving development planning orientation nuclear power in Viet Nam in the period to 2030, 8 potential sites are available in the Balmorel model (North Central – 1 site in Ha Tinh, Center Central – 2 sites in Quang Ngai, South Central – 5 sites in Binh Dinh, Phu Yen, Ninh Thuan). Each location is capable of building 4 to 6 nuclear power units with total capacity about 4 GW – 6 GW for each site.

Committed generation capacity

Some projects of coal fired power plants and gas fired power plants are under construction and will be committed in the model.

The coal power plant projects are committed in the period 2021-2030 as follow: Hai Duong (1200 MW), An Khanh – Bac Giang (650 MW), Na Duong II (110 MW), Thai Binh II (1200 MW), Nghi Son II (1200 MW), Quang Trach I (1200 MW), Van Phong I (1320 MW), Song Hau I (1200 MW), Long Phu I (1200 MW), Duyen Hai

II (1200 MW). Total installed capacity of coal fired power plants in 2030 will be about 30.5 GW (including existing and committed projects).
The domestic gas power plants projects are committed with about 3.8 GW using CVX gas and 3.8 GW using Block B gas. CCGTs using LNG projects are committed with 10.4 GW in period 2021-2030. Total installed capacity of natural gas fired power plants in 2030 will be nearly 25 GW (included existing and committed projects).

Existing and committed coal power plants are modelled with a minimum amount of FLHs of 6000 hours/year (BOT plants) and a maximum of 6600 hours/year. For existing and committed NG plants, the minimum is 5000 hours/year and the maximum 6600 hours/year.

Transmission system

For the transmission grid, input from the grid model PSS/E was used to find the current net transfer capacity (NTC) of the eight transmission lines between the seven regions (Table 6 and Figure 20). These capacities are based on a detailed representation of the Vietnamese transmission grid and include N-1 considerations.

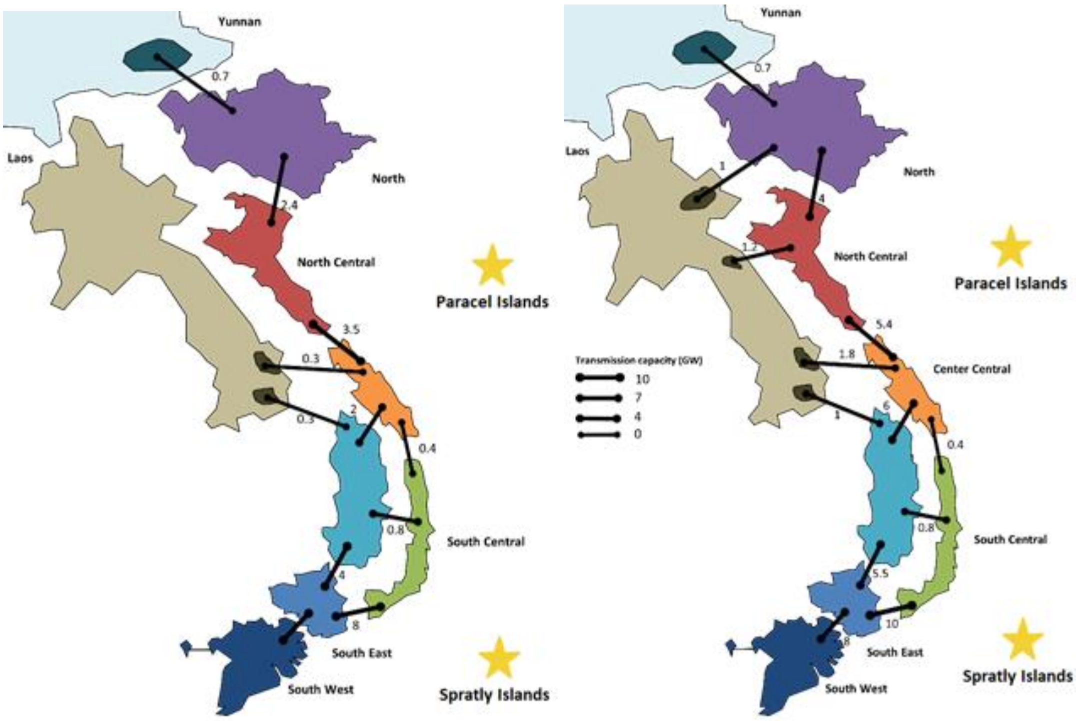


Figure 20: Transmission region and the current interconnectors in Viet Nam (2020, left and 2030, right)

From	To	MW
North	**North Central**	2,400
North Central	**Center Central**	3,500 (1,400 reverse)
Center Central	**Highland**	2,000
	South Central	400
Highland	**South Central**	800
	South East	4,000
South Central	**South East**	8,000 (3,500 reverse)
South East	**South West**	7,960

Table 6: Transmission capacity between regions in 2020.

Losses on transmission lines between regions are calculated according to Table 7. These losses are shown as percentage and are derived based on transmission line load of 80% for each line.

From	To	Losses on flow
North Central	North	3.2%
Center Central	North Central	3.6%
Highland	Center Central	2.5%
South Central	Center Central	3.8%
South Central	Highland	3.5%
South East	Highland	3.5%
South East	South Central	3.0%
South West	South Central	3.0%
South East	South West	3.2%
Center Central	North	6.0%

Table 7: Losses on transmission flow between regions.

External input data to PSS/E

To build PSS/E case file, the key data inputs include power sources, load at nodes, the transmission system include transmission lines and substations at different voltage levels.

Power plants

Based on input data from Balmorel for BSL scenario, there are 241 power plants in Viet Nam power system in 2025 and increase to 295 power plants in 2035 (some large power plants are divided into each unit and renewable energy source such as solar, wind and biomass are divided into each region). The PSS/E study need to assign power plants and loads to the nodes of transmission system, especially the solar and wind power:

- Large power plants: Build and update library linking Balmorel and PSS/E (excel file), that assign large power plants (coal, gas, large hydro) to corresponding buses in PSS/E.
- Wind, solar, small hydro, biomass and other RE are split by provinces and assign to suitable nodes in each province.
- Rooftop solar is distribution generation and is modelled as negative load at the load nodes (that made the PSS/E model more convergent than small distribution plants).

The load

PSS/E model receive load from Balmorel in 7 regions. The load is assigned to nodes in each region as the same ratio as in PDP8. In each snapshot, the total load of region will be scaled up or down to match snapshot input data.

The transmission system

The inter-regional transmission system will be built based on installed transmission capacity between region from Balmorel. The Balmorel model does not consider the local transmission network so the internal power grid in each region will be taken from draft PDP8. Other assumptions:

- *Power factor at load nodes (Cosφ):* The voltage on the grid depends very much on the power factor Cosφ at load node. Cosφ usually ranges from 0.9 to 1.0. The lower the Cosφ, the more reactive power the load consumes. This can lead to the lower voltage. Since the power grid simulated in this project only represents equivalent electrical load at 220 kV nodes, it is assumed that Cosφ = 0.98 – i.e., the average compared to the present (0.95-1.0).

- *Generator terminal voltage:* Traditional generators and modern inverters for wind and solar power can act as voltage control elements on the grid, by controlling the amount of emitting reactive power. However, the output voltage of the generators cannot be set too high or too low and must meet the requirements of the Grid code. In the grid simulation, it is assumed that the terminal voltage of generators varies within +/- 5% of the rated voltage.

- *Limitation capacity of transmission lines*: in this project, the thermal limit of transmission line is used (except for lines over 300 km using the limit capacity according to the condition of power system stability). *Limitation capacity of an interface* is taken from Total Transfer Capacity (TTC) calculation result.

- *Limit capacity of 500/220 kV transformers*: it is set according to the rated power of the transformer.

- *Resistor, resistance of line and transformer parameters (R_0, X_0, B_0):* typical parameters on the current transmission grid are used.

4 Energy scenarios

Main scenarios

The Energy Outlook Report 2021 focusses on the following 5 scenarios (Figure 21):

- **Baseline (BSL)**

  *The Baseline scenario can be seen as the **reference** scenario; it **includes existing policies** and contracted commissioning of new plants.*
- **Green power (GP)**

  *The Green power scenario looks at a more ambitious green power sector with **higher shares of RE and less coal.** This scenario uses the BSL results for the energy sectors other than the power sector.*
- **Green transport (GT)**

  *The Green transport scenario looks at a future with higher shares of **electrification in the transport sector**, combined with **more RE in the power sector**.*
- **Air pollution (AP)**

  *The Air pollution scenario looks at the effect of **considering air pollution** on the future energy system.*
- **Net-Zero (NZ)**

  *The Net-Zero scenario considers a future in which the **2-degree pathway** is achieved.*

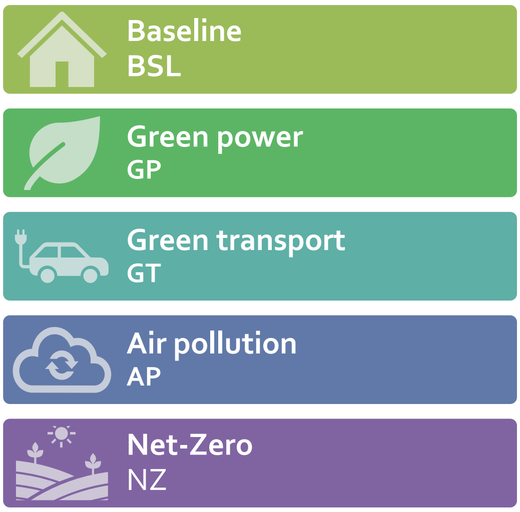


Figure 21: Main scenarios of the EOR21

The scenarios are executed within the EOR modelling framework explained in chapter 2 . The TIMES model runs are performed before the Balmorel model runs thereafter transferring outputs on the power sector to the Balmorel model. Additionally, BSL, GT, and AP include an extra iteration step, where Balmorel feeds back its power sector results for an updated TIMES run. For GP and NZ, the model runs ends after the first Balmorel run.

TIMES

An overview of the restrictions used in the TIMES-model can be seen in Table 8. In the following sections, the restrictions will be more thoroughly described.

Scenario	RE-share in primary energy	CO_2 emissions pathway	High electrification rate in TRA	Transport modal shift	Optimization of pollution cost
BSL	**Min. share** 15% in 2030 25% in 2045 (RES55)	**Max. emission** -15% in 2030 -20% in 2045 (vs BAU)	-	-	-
GP	=BSL	=BSL	-	-	-
GT	= BSL	= BSL	* Min. el. share of new cars/busses/trucks 75%/90%/90% by 2050 * 30% el. motor bikes by 2030 * 57% el. passenger train demand by 2050 * no new gasoline motor bikes from 2030	* Motor bike to metro in Hanoi and Ho Chi Minh City: 70% by 2050 * Freight to el. train: 35% by 2050	-
AP	= BSL	= BSL	-	-	**Included**
NZ	= BSL	2-deg./67% prob.: - peak in 2035 - aiming for zero in 2050	=GT	=GT	-

Table 8: Comparison of scenario restrictions for TIMES-Vietnam. A '-' denotes that the restrictions is not applied in the scenario, while a scenario acronym, e.g., 'BSL', denotes that the constraint in the scenario is the same as in the referred scenario.

RE-share in primary energy

The restrictions on the RE-share in primary energy supply, as seen in column 1 in Table 8, comes from the Resolution 55, where the aim is to have 15-20% renewables in primary energy by 2030 and 25-30% in 2045. It was chosen to aim for the lower values in these ranges. The share in the years in between the target years are set to follow a linear trend. The target for 2050 is also a linear extrapolation from the target in 2045. The restrictions are shown in Figure 22.

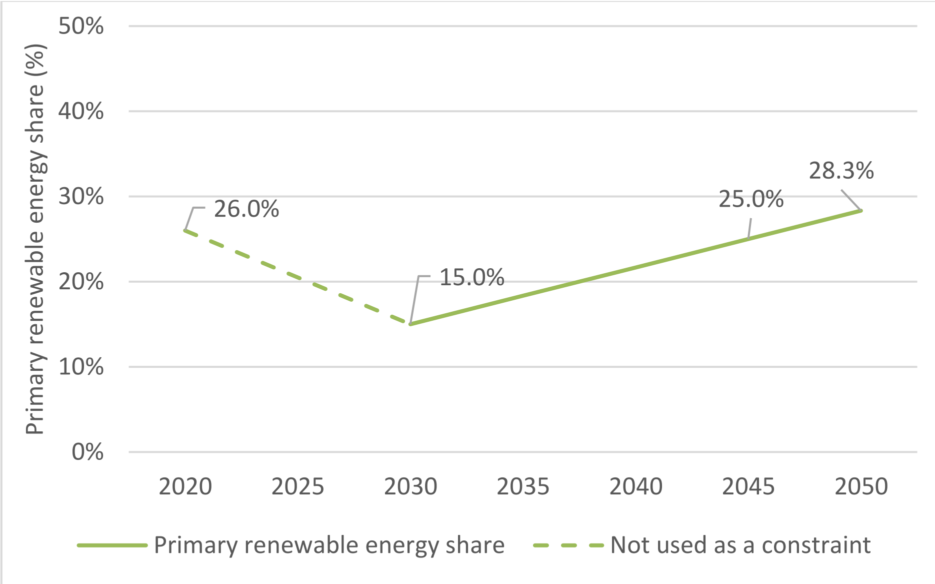


Figure 22: Restrictions on the RE-share in primary energy from the Resolution 55.

CO_2 emission pathways

The CO_2 emission pathways included in the model for the BSL scenario is given by the National Energy Development Strategy (Central Economics Committee, 2020). The BSL budget follows the assumptions to reduce emissions in 2030 by 15% and in 2045 by 20% compared to a business-as-usual scenario. Both budgets are plotted in Figure 23. For 2050, it is assumed that the emissions increase in both scenarios is the same from 2045 to 2050 as from 2040 to 2045.
For the Net-Zero scenario, the budget is found by using the resulting budget from the GT scenario model run up to 2030. The pathway from 2035 is created by considering an overall budget for the model horizon for Viet Nam of roughly 11 billion tons of CO_2 corresponding to a 2-degree scenario with 67% probability and by dividing the CO_2-budget of the world based 50% on the population size and 50% on the emissions in 2014. Furthermore, the pathway is set to peak in 2035. To create the CO_2-budget, the tool www.carbonbudget.world have been used. The tool gives the budget for all CO_2 emissions within Vietnam. Emissions from non-energy and uptake from LULUCF have not been included in the model. These emissions are assumed to outweigh each other so that the CO_2 budget for the energy sectors is the same as the overall budget for Vietnam. The TIMES-model at the current state cannot make a full decarbonisation of the entire system due to limitations on technology shift in the end-use sectors. However, this is only a modelling issue – a full decarbonisation of end-use sectors is possible by, e.g., use of more biofuels, hydrogen, or electrification. Because of the issues with the current state of the model, the CO_2 budget in 2050 is set to the lowest possible value for the TIMES model to solve, which is 110

Mtons CO_2. An overview of the CO_2 emission pathways used in TIMES for the scenarios are shown in Figure 23.

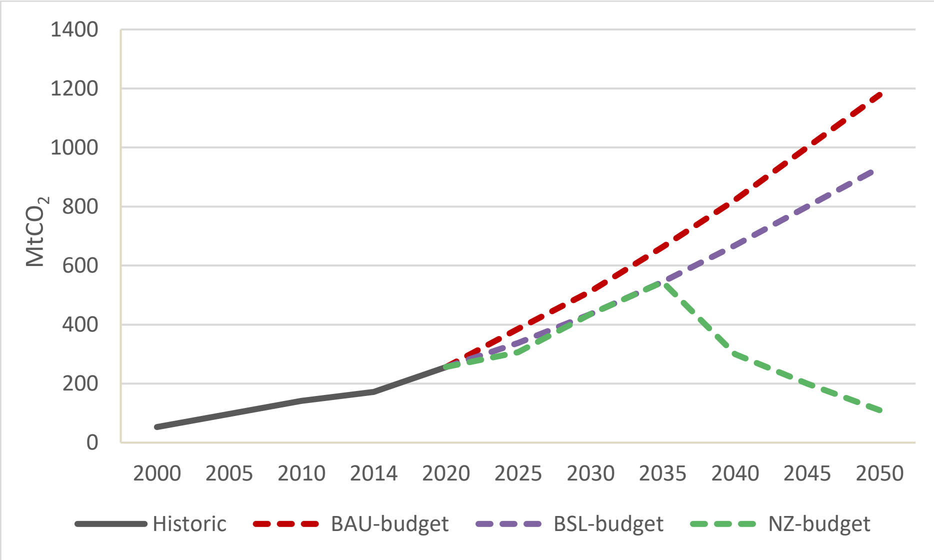


Figure 23: CO_2 emission pathways for the BSL- and NZ-scenarios as used in TIMES

High electrification rate in the transport sector

The high electrification rate in transport is included in the model by several restrictions. The first type of restrictions relates to the share of new vehicles in the system that must be electric. In Figure 24, the restriction is shown for the cars, busses, trucks, and motorbikes. The most drastic restriction is for the motorbikes, where all new motorbikes must be electric by 2030. This means a total ban on new gasoline motorbikes in 2030. On top of the restriction on new capacities, a restriction on all motorbikes have been set for the year 2030, saying that at least 30% of all motorbikes must be electric.

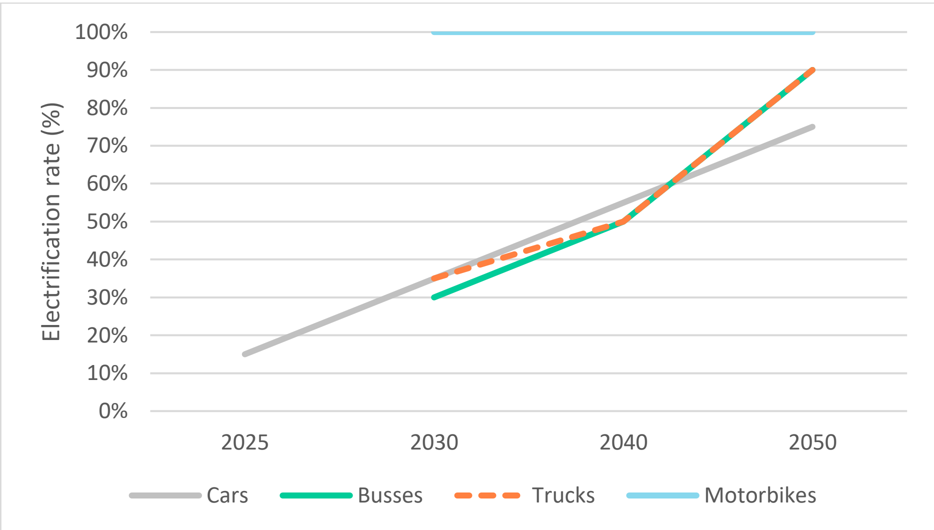


Figure 24: Minimum electrification of new capacities for cars, busses, trucks, and motorbikes.

For the passenger train demand, the electrification is driven by the move towards a high-speed railway assumed to be in operation by 2030. In Figure 25, the share of the demand from 2030 to 2050 is given. Here, the share of the freight train demand is also given. The share for freight is found by applying the assumptions on modal shift as given below.

Figure 25: The share of the demands that are served by electric options for passenger and freight trains

Transport modal shift

For the freight transport, an assumption for modal shift have been applied to reflect a North-South high-speed railway system that allow for freight transport. The assumption applied here is that 5% of the freight transport in 2030 would be served by this system, increasing linearly up to 35% in 2050. For this shift, only electric trains can be used to serve the demand (as reflected in Figure 25).

For motorbikes, an assumption on a shift to metro is applied to allow for shifting the demands from motorbikes to metro in Hanoi and Ho Chi Minh City. The assumption here is that 50% of all motorbikes in these two cities are moved to metro in 2035 – linearly increased from 0% in 2024. A further increase up to 70% in 2050 is applied for these two cities. The resulting demands are shown in Figure 26.

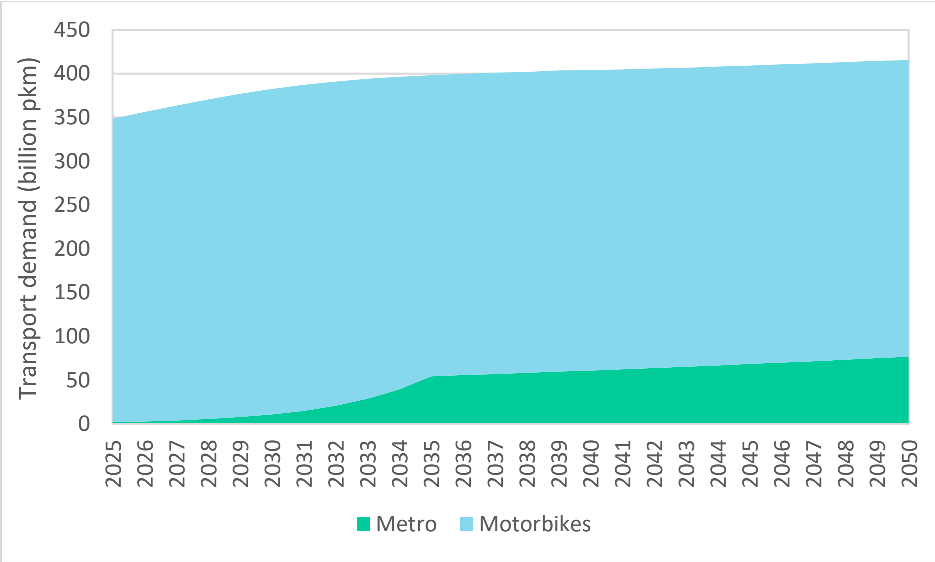


Figure 26: Resulting demand for metro and motorbikes based on the modal shift assumptions

Optimization of pollution cost

Pollution costs have been added to the models using the same methodology as described in the Annex, p. 103. As described in the report, the pollution costs have been found using the EVA-system (Economic Valuation of Air pollution), relying on calculation by the DEHM-model (Danish Eulerian Hemispheric Model). The EVA-system considers different costs per sector, depending on where the sectors are emitting. Adding pollution costs to the optimization is a rather novel approach for energy systems models.

The found pollution costs have been projected to future costs by assuming a direct relationship with population size, e.g., the costs for 2050 have been scaled by taking the costs from the EVA-system and multiplying with population size in 2050 and dividing with population size in 2016 (the costs are calculated for the year 2016).

The air pollutants considered in the energy systems models are NO_x, SO_2, and $PM_{2.5}$, and the resulting pollution costs per sector are given in Figure 69 as seen in the Annex. The residential and commercial sectors are assumed to have the same pollution costs, as are the agricultural and the road transport sectors – as illustrated in Figure 69.

Each technology in TIMES and Balmorel have an associated emission factor. For the specific emission factors for each of the technologies, see p. 106. For the supply sector, the emission factors have been excluded as there were some uncertainties of the size of these.

Balmorel

An overview of the restrictions use in the Balmorel model can be seen in Table 9.

Scenario	Committed capacity	Investment restriction	RE-share	Max RE capacity	Pollution cost optimization	CO_2 limit
BSL	**Based on PDP8** * Until 2026 * No BOT plants	**No new coal after 2035**	**Min. share** 38% by 2020, 32% by 2030 43% by 2050	**Maximum** 22 GW PV in 2030	-	-
GP	=BSL	=BSL	**Min. Share** 38% by 2020 38% by 2030 75% by 2050	-	-	-
GT	=BSL	=BSL	**Min. share** = BSL all additional power demand from transport = RE	-	-	-
AP	=BSL	=BSL	= BSL	-	**Included**	-
NZ	=BSL	=BSL	= BSL	-	-	**Included** from TIMES results

Table 9: Comparison of scenario restrictions for Balmorel-Vietnam. A '-' denotes that the restrictions is not applied in the scenario, while a scenario acronym, e.g., 'BSL', denotes that the constraint in the scenario is the same as in the referred scenario.

In Figure 27 the minimum share of renewable energy sources is shown for all the scenarios. For the *BSL*, *AP,* and *NZ* scenario the minimum share is based on the REDS (Renewable Energy Development Strategy) target. The *GP* scenario keeps a flat share of 38% until 2030 and then linearly increased until 75% in 2050. The GT scenario restriction is based on the BSL scenario results, where all additional demand due to the electrification of the transport sector will come from renewables.

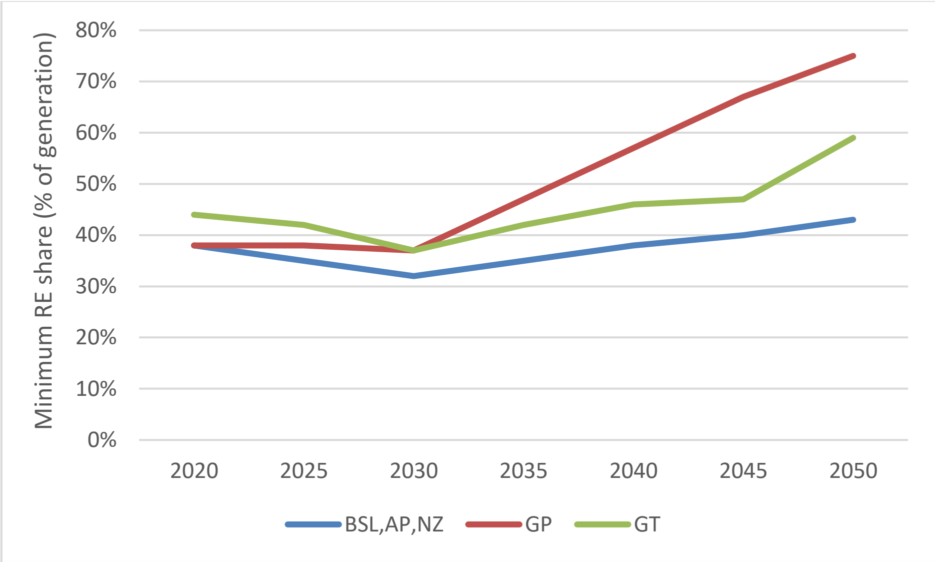


Figure 27: Minimum share of renewable energy sources in electricity mix are set in model.

Sensitivity analyses

Figure 28 shows the sensitivity scenarios that have been analysed. In the figure, the main scenario of which the sensitivity is based on is shown in parenthesis after the name. The scenarios have been selected to analyse some of the key parameters in the model, which at the same time have a potentially significant effect on the pathways.

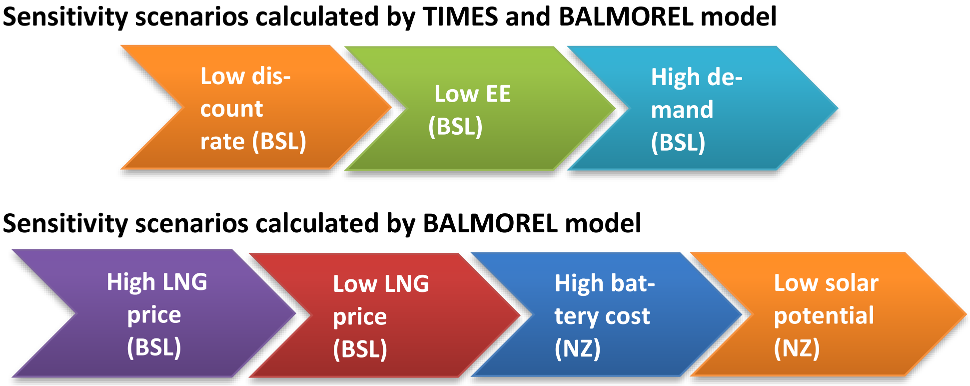


Figure 28: Sensitivity scenarios.

Three sensitivity scenarios have been performed by running both the TIMES and Balmorel models, namely: Low discount rate, Low EE, and High Demand. The results of new power demand, use of biofuels for power generation from TIMES model in these scenarios will be transferred for Balmorel model. Four scenarios have been chosen only to run with the Balmorel model, as the effect of these parameters mainly will affect the power sector. These scenarios are: High LNG price, Low LNG price, High battery cost, and Low solar potential.

The sensitivity analyses are named by the chosen uncertain input parameters and are described below:

- **Low discount rate scenario**: In the BSL scenario, social discount rate is assumed to be 10% due to regulations of the Ministry of Industry and Trade in economic and financial analysis of power generation projects. This sensitivity scenario sets the social discount rate to 6.3% as the low estimate from OECD (Coleman, B., 2021). All policies in this scenario are based on the BSL scenario.
- **Low EE scenario**: Only 50% penetration of energy efficiency as compared to BSL scenario, so that energy demand will be higher than in the BSL scenario. Policies in this scenario are based on the BSL scenario.
- **High demand scenario**: High forecasted GDP growth rate, which is taken from a study of Vietnam institute for development strategies (2021) "Research and forecasting the Viet Nam economic development scenario", will be used to calculate energy demand in TIMES model. The energy demand in this sensitivity will be higher than in the BSL scenario, see Figure 29. This sensitivity analysis is based on the BSL scenario.

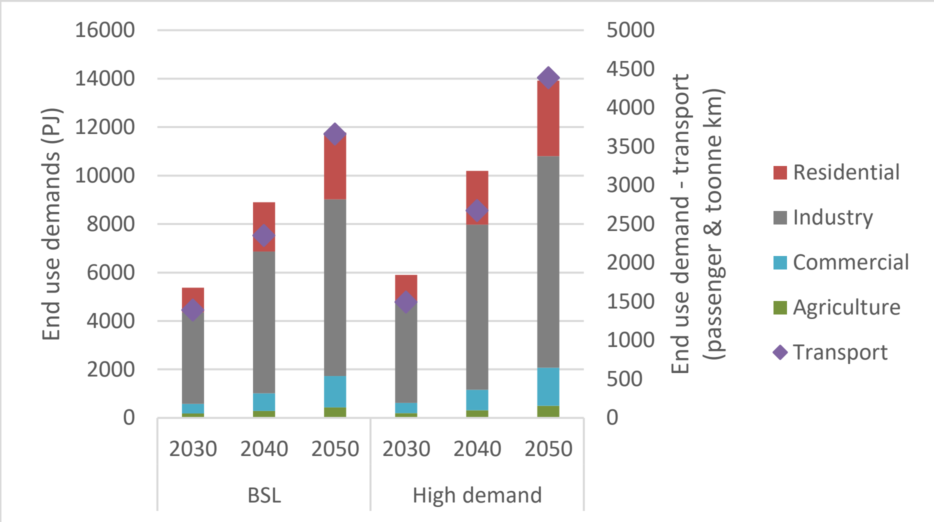


Figure 29: Comparison of end use demands for the BSL and High demand scenario

- **High and Low LNG price scenarios**: The base fuel price (use for all main scenarios) assumptions are from the Stated Policies scenario in the World Energy Outlook (WEO) report (IEA 2020), which corresponds to the highest scenario in the Fuel Price Projection Report (EREA and DEA, 2021a). So, in the higher fuel price scenario, prices of imported LNG are 20% higher than the base case. The low LNG price scenario will be using forecasted fuel prices from the Sustainable development scenario in WEO as found in the Fuel Projection Report. The development in LNG price is shown in Figure 30. Both sensitivity analyses are based on the BSL scenario.

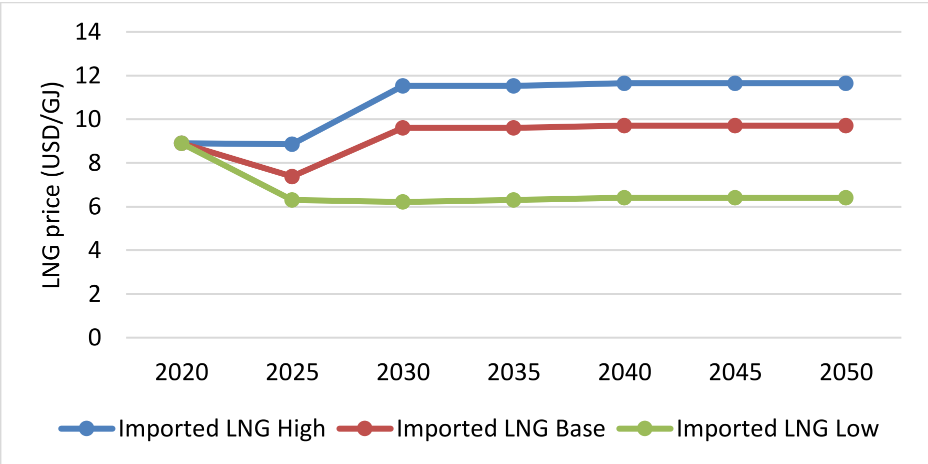


Figure 30: Imported LNG price projection (real USD 2019)

- **High battery cost scenario**: Costs for batteries are expected to decline dramatically, just how much might be key to how big their role will be in the future power system. In Vietnamese technology catalogue (EREA and DEA, 2021b), cost of battery is forecasted from low to high cases. Main assumptions used in the main scenarios are chosen to be the medium case. This sensitivity analysis will run with the high investment costs to investigate the impact on the power system. A comparison of the costs is shown in Figure 31. This sensitivity analysis is based on the NZ scenario.

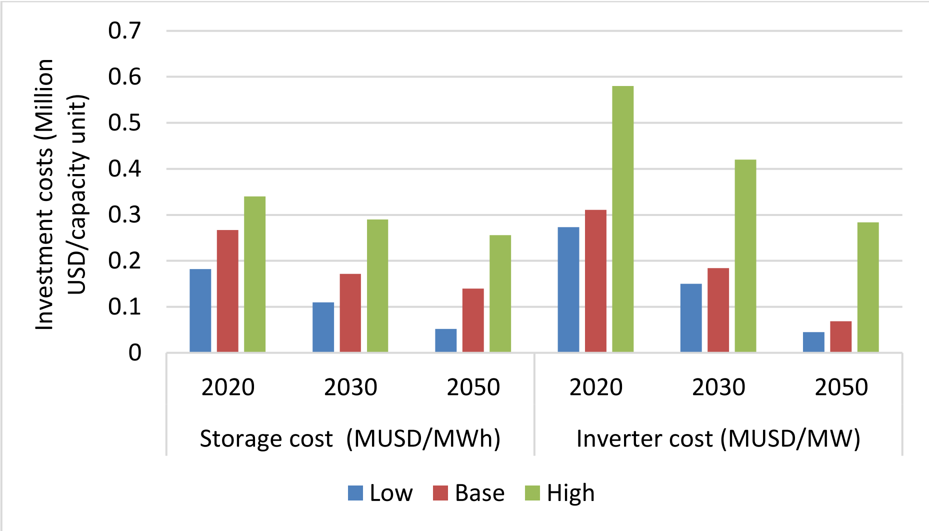


Figure 31: Battery investment cost projection in Vietnamese Technology Catalogue (EREA and DEA, 2021b).

- **Low solar potential scenario:** Technical potential of utility solar PV in the NZ scenario at approximately 800 GW affects heavily the land-use. Therefore, this sensitivity will assume to have only half of the technical potential of utility solar PV. The rest of the assumptions are based on the NZ scenario.

5 Modelling results – Main scenarios

This chapter presents the modelling results for the five main scenarios analysed in the linked modelling framework using TIMES and Balmorel. The results cover the whole energy system, from primary resource use to final energy demand and service demands in the end-use sectors, as well as illustrating disaggregated results for the power sector. Results regarding the power sector are exclusively from Balmorel, whilst the results for the other sectors come from TIMES.

Primary Energy Supply

The total primary energy supply (TPES) increases significantly from 2020 in all scenarios (see Figure 32). This is a result of the increase in energy demands for all the scenarios.

In BSL, this increase is a factor of 3.5 from 2020 towards 2050, increasing the energy consumption from 937 PJ in 2020 to 3338 PJ in 2050. Alongside, the share of renewable energy in TPES increases moderately by 4% from 22% to 26% mainly due to higher utilisation of solar and wind energy.

TPES in GT, AP, GP, and NZ are lower compared to BSL. In GT, the TPES decreases by 1.3% (25 PJ) in 2030 and 1.6% (52 PJ) in 2050 compared BSL, due to the changing from private to public transport in mega cities, the development of high-speed railway, and increase of the electrification rate. Considering the effect of air pollution costs on the energy system, there is a decrease of TPES by 54 PJ (2.85%) in 2030, and 104 PJ (3.13%) in 2050 because more efficient technologies are being used. In NZ, to meet the target of reducing CO_2 emission, the TPES decreases by 104 PJ (5.5%) in 2030, 532 PJ (19%) in 2040, and 572 PJ (17%) in 2050 compared to BSL scenario. Again, this is because of an increased electrification and selection of more efficient technologies.

The renewable shares increase across the scenarios. Especially in NZ, the share of renewable reach 55% in 2040, and 90% in 2050. The biggest contribution is from solar energy, accounting for 53% in total TPES. NZ

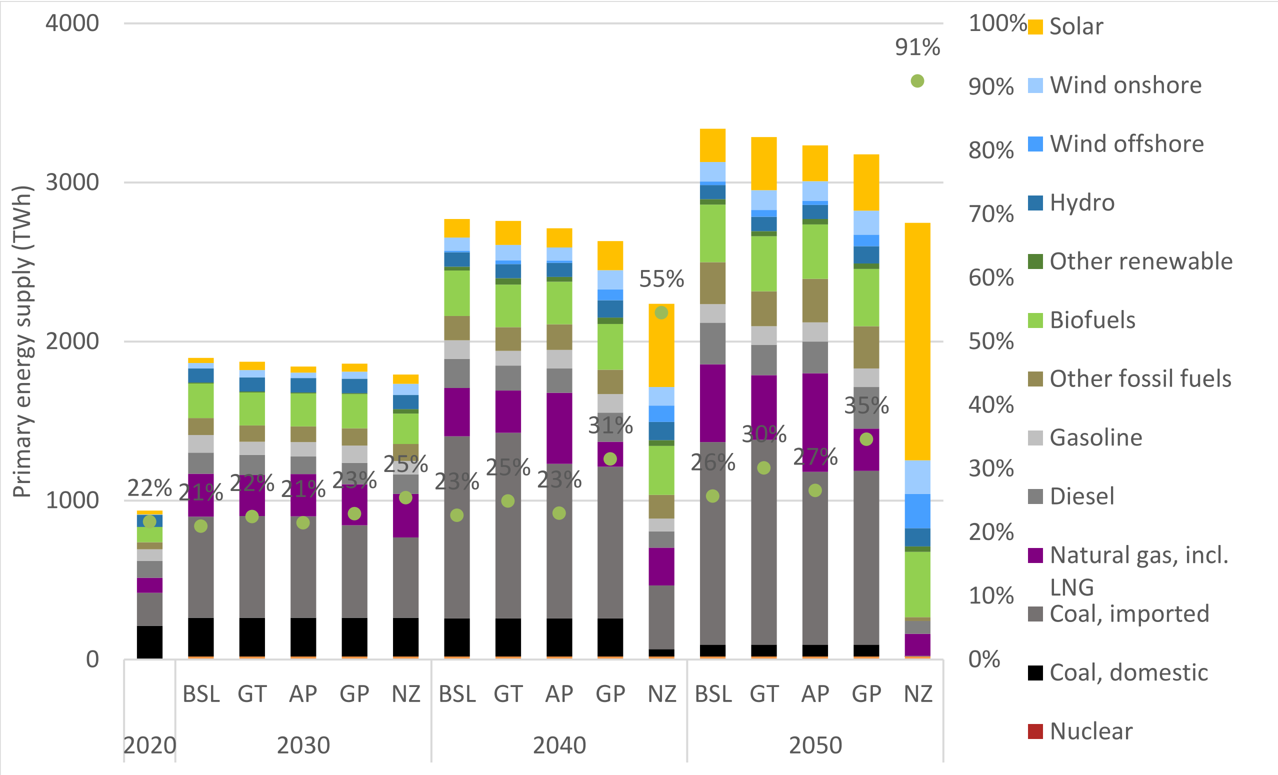


Figure 32: Primary energy supply by fuel

Final Energy Consumption

In BSL, final energy consumption (FEC) rises at the rate of 4.8% annually, from 2530 PJ in 2020 to 10849 PJ in 2050. Industry is the largest consumer which accounts for 56% in 2020, 66% in 2030, 64% in 2040, and 60% in 2050 in total FEC. Transportation is the second largest consumer accounting for 21% in 2020, 14% in 2030, 13% in 2040, and 15% in 2050.

Under the effects of promoting green strategies as in GT, FEC reduces by 2.4% (134 PJ) in 2030, 1.4% (117 PJ) in 2040, and 2.1% (231 PJ) in 2050. The share of transportation is also lower compared to BSL. The transport sector portion of the FEC is 13% in 2030, 12% in 2040, and 14% in 2050.

With consideration of air pollution costs, FEC declines by 3.2% (175 PJ) in 2030, 2.1% (175 PJ) in 2040, and 2.7% (286 PJ) in 2050.

The strict constraint on CO_2 emissions causes a shift towards electrification and thereby a sharp reduction in the FEC in NZ, by 9.0% (747 PJ) in 2040, and up to 20.0% (2115 PJ) in 2050.

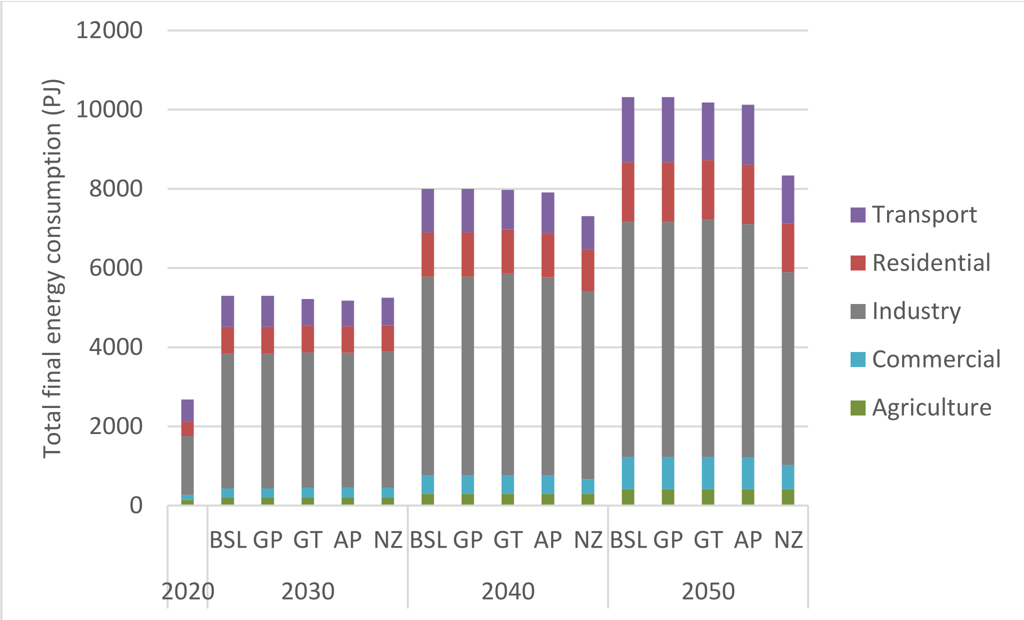


Figure 33: Final energy consumption in five scenarios

CO_2 emission

The CO_2 emissions from all the main scenarios are shown in Figure 34. In the period from 2020 to 2040, total CO_2 emissions grow for all the main scenarios. For NZ, there is a sharp decrease after 2040 to be able to meet the reduction requirements. For the other scenarios, the increase is emissions in the period from 2020 to 2050 corresponds to 3.8% per annum in BSL, 3.3% in GP, 3.6% in GT, and 3.6% in AP.

The promotion of green solutions in transportation helps to reduce the overall CO_2 emissions by 11 $MtCO_2$ (2.4%), 14 $MtCO_2$ (2.1%) and 45 $MtCO_2$ (5.9%) in 2030, 2040, 2050, respectively, when comparing GT with BSL. Considering the cost of air pollution also have a positive impact on the amount of CO_2 emissions, which are reduced by 14 $MtCO_2$ (3.0%), 34 $MtCO_2$ (5.0%), and 51 $MtCO_2$ (6.7%) in 2030, 2040, and 2050, respectively, when comparing AP with BSL scenario. An increase in the share of renewable energy in the power sector helps to reduce CO_2 emission by 21 $MtCO_2$ (4.4%), 96 $MtCO_2$ (14%), and 108 $MtCO_2$ (14%) in 2030, 2040, and 2050 respectively when comparing GP with BSL.

The power sector and industrial sector are the main emitters in the energy system in BSL, GT, AP, and GP. In BSL, the share of emission from the power sector is 46%, 41%, and 30% in 2030, 2040, and 2050, respectively. Emissions from the industrial sector account for 33%, 39%, and 43% in 2030, 2040, 2050, respectively.

In GP, the share of emission from the power sector decreases from 44% in 2030 to 32% in 2040, and to 18% in 2050. Emissions from the industrial sector account for 34% in 2030, 45% in 2040, 50% in 2050. In AP, the share of emissions from power decreases from 48% in 2030 to 39% in 2040, and to 27% in 2050. While the share of emissions from industry increases from 34% in 2030 to 41% in 2040, and to 46% in 2050.

When comparing BSL and GT, the transport sector accounts for 9.4 $MtCO_2$ in total 11 $MtCO_2$ reduction in 2030, and 31 $MtCO_2$ out of 45 $MtCO_2$ reduction in 2050.

In NZ, the emission reaches the peak in 2035. The growth rate of CO_2 emissions is 4.1% in the period from 2020 to 2035. After that, the emission decreases at the rate of 12% up to 2050. With the combination of solutions from all sectors, the CO_2 emission reduces by 139 $MtCO_2$ (24%) in 2035 and even by 691 $MtCO_2$ (91%) in 2050 when comparing NZ and BSL scenario. The remaining CO_2 emissions in the NZ scenario sum to 65 $MtCO_2$. The necessary measures to reach net zero emissions in 2050 will be calculated outside of the models.

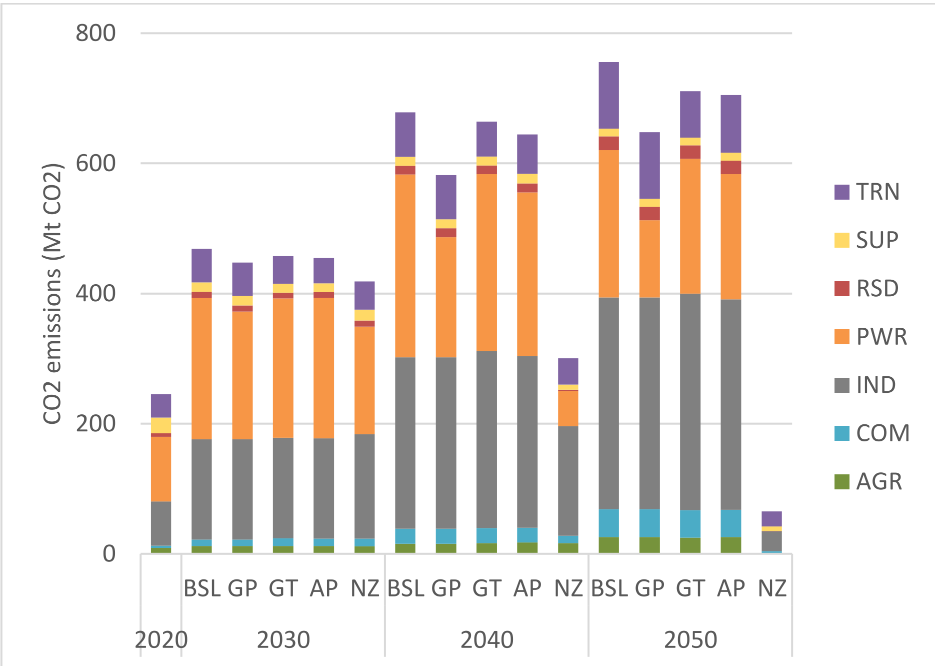


Figure 34: CO_2 emission by sectors from main scenarios ($MtCO_2$)

In 2020-2050, total CO_2 emissions grows by 3.82% per annum in BSL scenario, 3.61% in GT, 3.58% in AP scenario, and 3.28% in GP scenario. The promote of green solutions in transportation helps to reduce CO_2 emission by 11 $MtCO_2$ (2.4%), 14 $MtCO_2$ (2.1%) and 45 $MtCO_2$ (5.9%) in 2030, 2040, 2050 respectively when comparing GT scenario with BSL scenario. Considering the cost of air pollution will help in reducing CO_2 emission by 14 $MtCO_2$ (3.0%), 34 $MtCO_2$ (5.0%), and 51 $MtCO_2$ (6.7%) in 2030, 2040, and 2050 respectively when comparing AP scenario with BSL scenario. Increase the share of renewable energy in power sector helps to reduce CO_2 emission by 21 $MtCO_2$ (4.4%), 96 $MtCO_2$ (14.2%),

and 108 $MtCO_2$ (14.3%) in 2030, 2040, and 2050 respectively when comparing GP scenario with BSL scenario.
Power sector and Industry sector are the main emitters in the energy system in BSL, GT, AP, and GP. In BSL scenario, the share of emission from power sector is 46%, 41%, and 30% in 2030, 2040, and 2050 respectively. Emission from Industry section accounts for 33%, 39%, and 43% in 2030, 2040, 2050 respectively.
In GP scenario, the share of emission from power decreases from 44% in 2030 to 32% in 2040, and to 18% in 2050. Emission from industry sector accounts for 34% in 2030, 45% in 2040, 50% in 2050.
In AP scenario, the share of emission from power decreases from 48% in 2030 to 39% in 2040, and to 27% in 2050. While the share of emission from industry increases from 34% in 2030 to 41% in 2040, and to 46% in 2050

When comparing BSL and GT scenario, transport sector accounts for 9.4 $MtCO_2$ in total 11.2 $MtCO_2$ reduction in 2030, and 30.7 $MtCO_2$ out of 44.8 $MtCO_2$ reduction in 2050.

Total System Cost

The total system cost can be broken down into capital costs, fixed operation and maintenance (O&M) cost, fuel costs, variable O&M cost, and air pollution cost. The annual costs are discounted using a discount rate of 10 % to the year 2015. The entire system costs by type and scenario are presented in Figure 35.

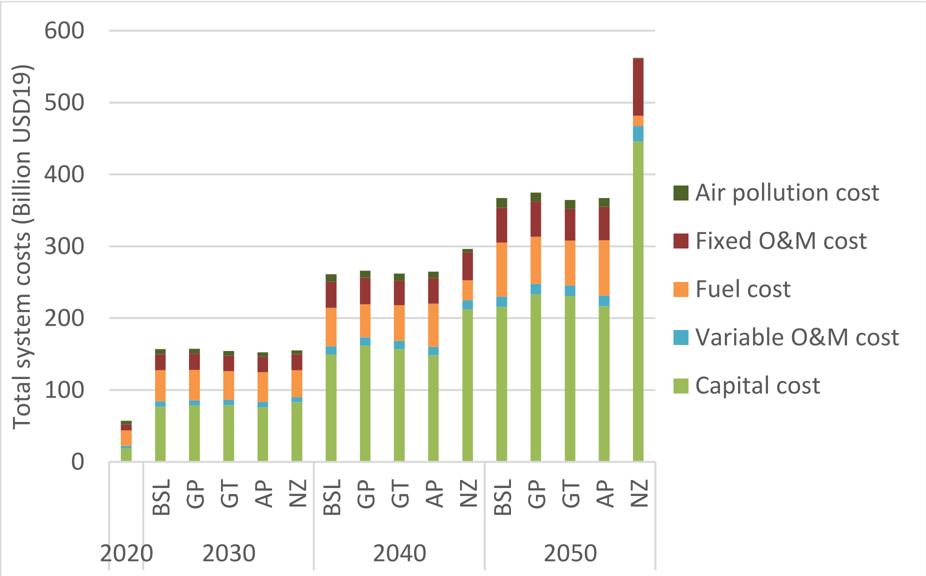


Figure 35: Annual total system cost in five scenarios

In BSL, total cost increases by average 6.4% annually from 56 billion USD19 in 2020 to 367 billion USD19 in 2050. In AP, the total cost also increases by an average of 6.4% annually. The cost in 2050 is very close to that of BSL. For GT, the system costs in 2050 are 2.5 billion USD19 lower compared to BSL. In GP, the annual growth rate of total costs is 6.5%. Only in NZ, the investment cost increases dramatically, due to the investment of high energy efficiency technologies and renewable energy technologies. As a result, total system costs are 562 billion USD19 in 2050.

Considering each type of system cost, it is evident that the capital cost accounts for the largest share in total system cost for all scenarios in the future years and increases heavily in the future. While most of the costs are at a similar level across scenarios, the fuel costs, capital costs and air pollution costs show to be very different for the NZ scenario compared to the other scenarios in 2040. For 2050 also the amount of fixed O&M is much higher in the NZ compared to the other scenarios. The air pollution costs are almost 10% of the air pollution costs in the NZ scenario compared to the other scenarios in 2050. Again, this relates to the chosen technologies in the system.

Linked data from TIMES and Balmorel

The TIMES model provides the input of total electricity consumption, the emissions limitation and maximum biofuel limitation to the Balmorel model. This ensures that the power sector is cost-effective under the right conditions of the overall energy sector. The total electricity consumption of each scenario and years is shown in Figure 36.

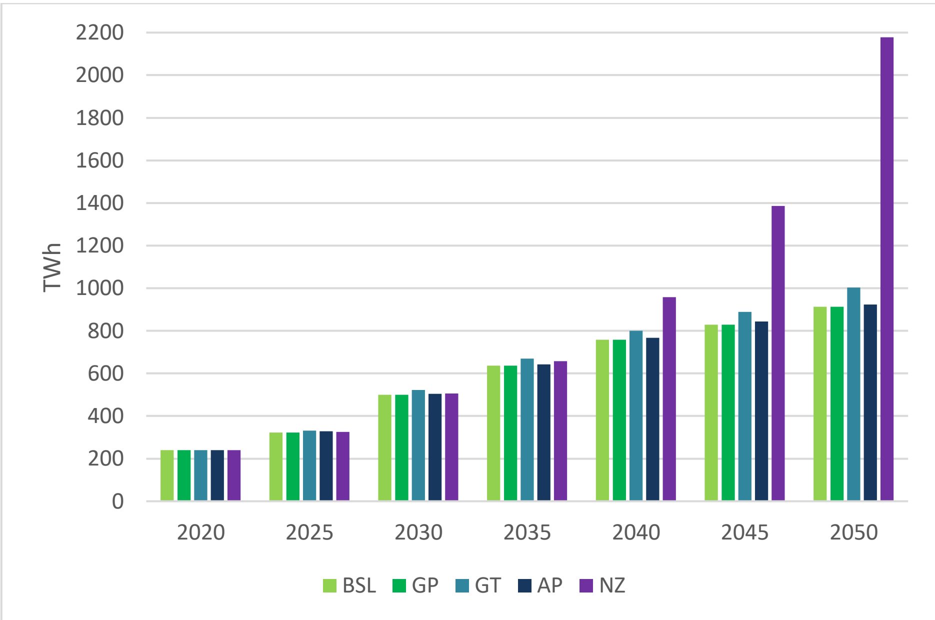


Figure 36: Total Vietnamese electricity consumption (including losses) optimized in the TIMES model and linked in the Balmorel model.

The power demand received from TIMES and implemented in Balmorel comes in 5 categories: Residential, commercial, EV, Industry (includes agriculture) and P2X (Power-to-X). Out of these, the EV demand and Industrial demand is modelled with some demand flexibility, as a fraction of the demand can be used to shift consumption for a limited period within a day. This represents demand elasticity with respect to power prices.

Most scenarios follow the same trend in electricity consumption increase while the Green Transport scenario is higher due to electrification of the transport sector. The electricity consumption of the Net-Zero scenario is significantly increased between 2040 to 2050 to reach the greenhouse gas reduction targets. The following graph shows the greenhouse gas limitations of the Net-Zero scenario.

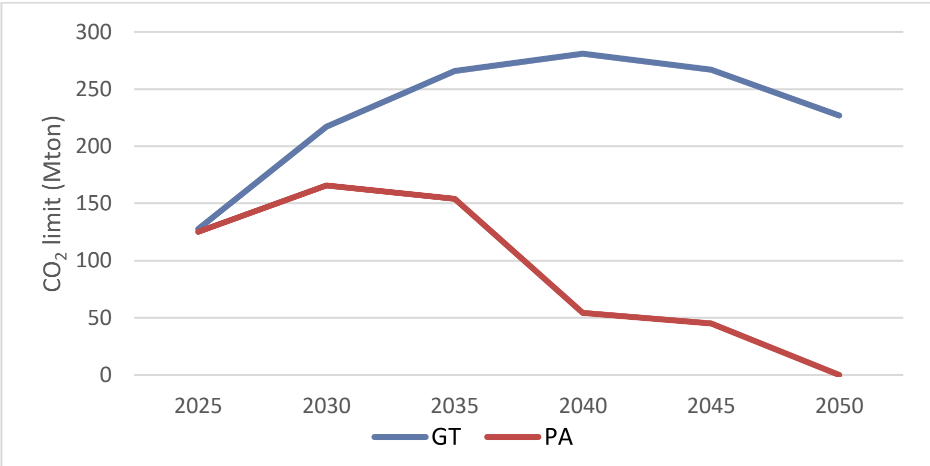


Figure 37: CO_2 allocation for the power sector from TIMES to Balmorel for the Net-Zero scenario

The greenhouse gas emissions of the power sector in Net-Zero scenario peaks at 166 million tons CO_2 in 2030 and then decreases to 0 million tons in 2050.

The bagasse, biomass and municipal solid waste (MSW) fuel potentials of each scenario and year are shown in Table 10. The availability of these resources is determined by the TIMES model as they can be applied in other sectors. For example, the transportation sector could use biomass resources to produce bio-fuels to function as an alternative to gasoline. Balmorel is not forced to use the potentials, and the combined results show that the potential is not used fully in any of the scenarios. In the NZ scenario, this leads to a full utilisation of the biomass resources in the TIMES model but with the Balmorel results, more biomasses could have been used for production of biofuels. This is not captured in the model setup, as the results from Balmorel is not fed back into the TIMES model in the NZ scenario.

PJ	BSL/GP			GT		
	Bagasse	Biomass	MSW	Bagasse	Biomass	MSW
2020	29	12	11	29	12	11
2025	47	22	21	47	22	21
2030	47	3	21	47	7	21
2035	55	8	21	55	0	21
2040	68	9	21	68	17	21
2045	69	2	10	69	0	10
2050	72	-	-	72	0	0
PJ	AP			NZ		
	Bagasse	Biomass	MSW	Bagasse	Biomass	MSW
2020	29	12	11	29	12	11
2025	47	22	21	47	22	21
2030	47	3	21	47	5	21
2035	55	7	21	55	7	21
2040	68	7	21	68	2	21
2045	69	-	10	69	0	10
2050	72	-	-	72	-	-

Table 10: Biomass fuel availability for the power sector from TIMES model to Balmorel

Power system results

With the starting point in the results of the TIMES simulations, through the inputs described in the previous section, the Balmorel model subsequently simulates the power sector in the 5 main scenarios in greater detail.

Power generation mix

Figure 38 shows the annual generation for the five main scenarios. While in the year 2030, the scenarios are relatively similar, by 2040 and 2050 larger differences show. The generation capacity can be seen in Figure 39.

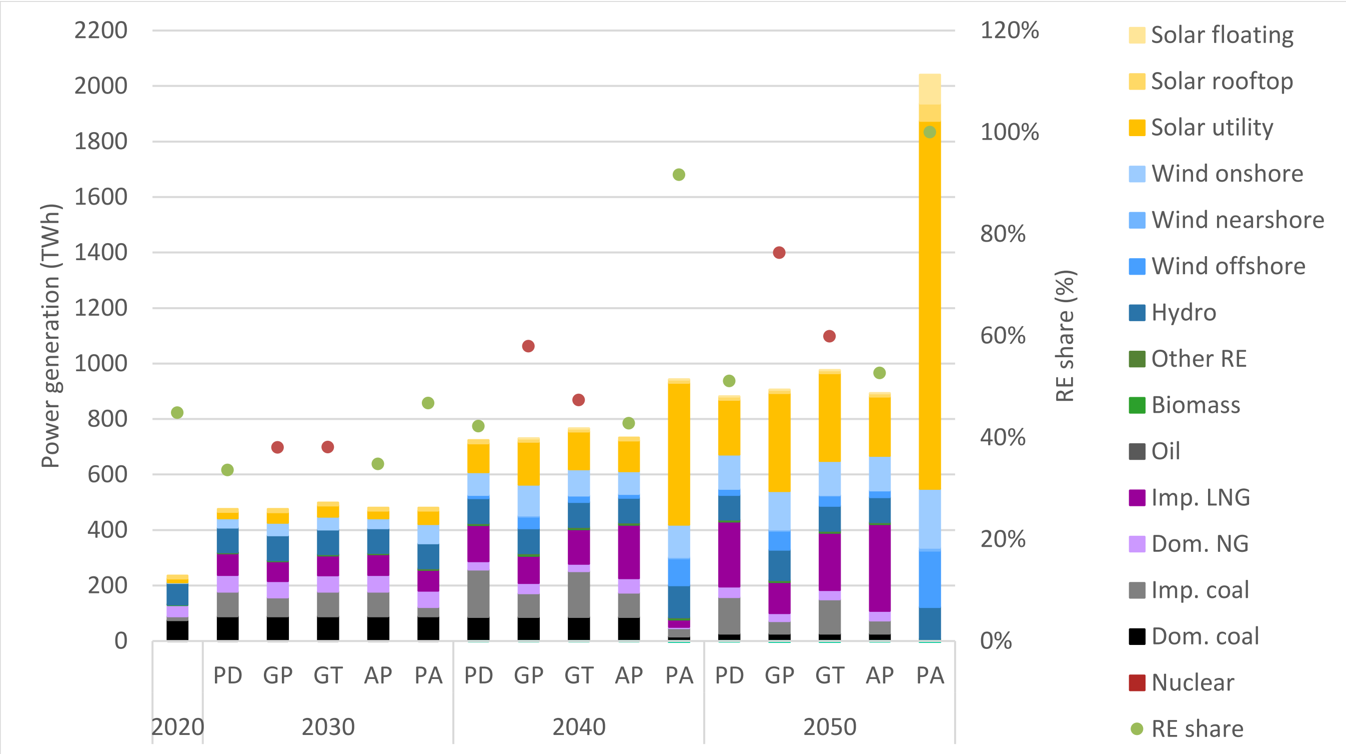


Figure 38: Annual generation and RE share for the five main scenarios in 2020, 2030, 2040 and 2050. The RE share is indicated in red when it matches the minimum requirement implemented in the model. The RE share indicated in green means it surpasses the minimum requirement.

The *Baseline* scenario, which can be seen as a reference scenario, shows significant RE generation, which in all years lies above the REDS target as was implemented, indicating that investments in RE generation is attractive from a socio-economic perspective. RE shares of 34% and 51% found as optimal in 2030 and 2050 respectively in the baseline scenario. In 2050, the total wind capacity ends at 46 GW responsible for 16% of the generation and the total solar capacity is 135 GW, good for 24% of generation. Due to the restriction on new coal after 2035, the share in natural gas generation increases towards 2050 and is mainly fuelled by imported LNG.

The *Green Power* scenario has the same starting point as the *BSL* scenario (same results for the non-power sectors and same TIMES input to Balmorel) but is showing a much greener trajectory for the power sector, with a minimum requirement constant at 38% until 2030 and then rising to 75% in 2050 as shown in Figure 39. This requirement is higher than the REDS scenario in all years after 2020 and becomes a binding restriction. The increase in RE generation is expressed as larger generation of wind and solar. In 2040, the largest increase is in wind generation now responsible for 22% of generation, while by 2050 larger solar generation is seen in comparison with the *BSL* scenario (41%). It is LNG and imported coal that see diminishing generation because of the higher RE production.

The *Green Transport* scenario also sees a forced increase in RE share. In this scenario due to the requirement that increases in power demand compared to the *BSL* scenario are required to be fulfilled by RE generation. The additional generation is primarily wind and solar, resulting in 18% and 37% of total generation respectively.

The *Air Pollution* scenario is in set-up identical to the *BSL* scenario, though counts the health-related externality costs of pollution when minimizing the total costs. This has virtually no impact on the results in 2030, though decreases the coal generation in 2040 and 2050 to about the same level as in the *GP* scenario. Unlike the *GP* scenario however, the decrease in coal generation is not so much compensated by wind and solar, but rather by a large increase in LNG fuelled power generation, indicating that when considering the health of the Vietnamese population, reduction of coal generation is first priority, where natural gas is a much less polluting fuel.

Finally, the *Net-Zero* scenario is the most ambitious scenario of the five considered here. As the power sector is the easiest to decarbonize, it is significantly larger in the *NZ* scenario than in the other scenarios as can be seen from Figure 36. Furthermore, the scenario is allowed only modest increases in CO_2 emissions in 2030 and 2035, followed by rapid decline in annual emissions in 2040, ending in zero emission by 2050. In terms of the electricity mix, these conditions result in drastic changes already in 2030, with a significant decrease in imported coal generation. By 2040, this decrease continues, and coal generation is largely displaced by nuclear, solar and wind, including significant offshore wind. This trend continues in 2050 with large solar and wind capacities. At that time, wind accounts for 21% and solar for 73% of generation.

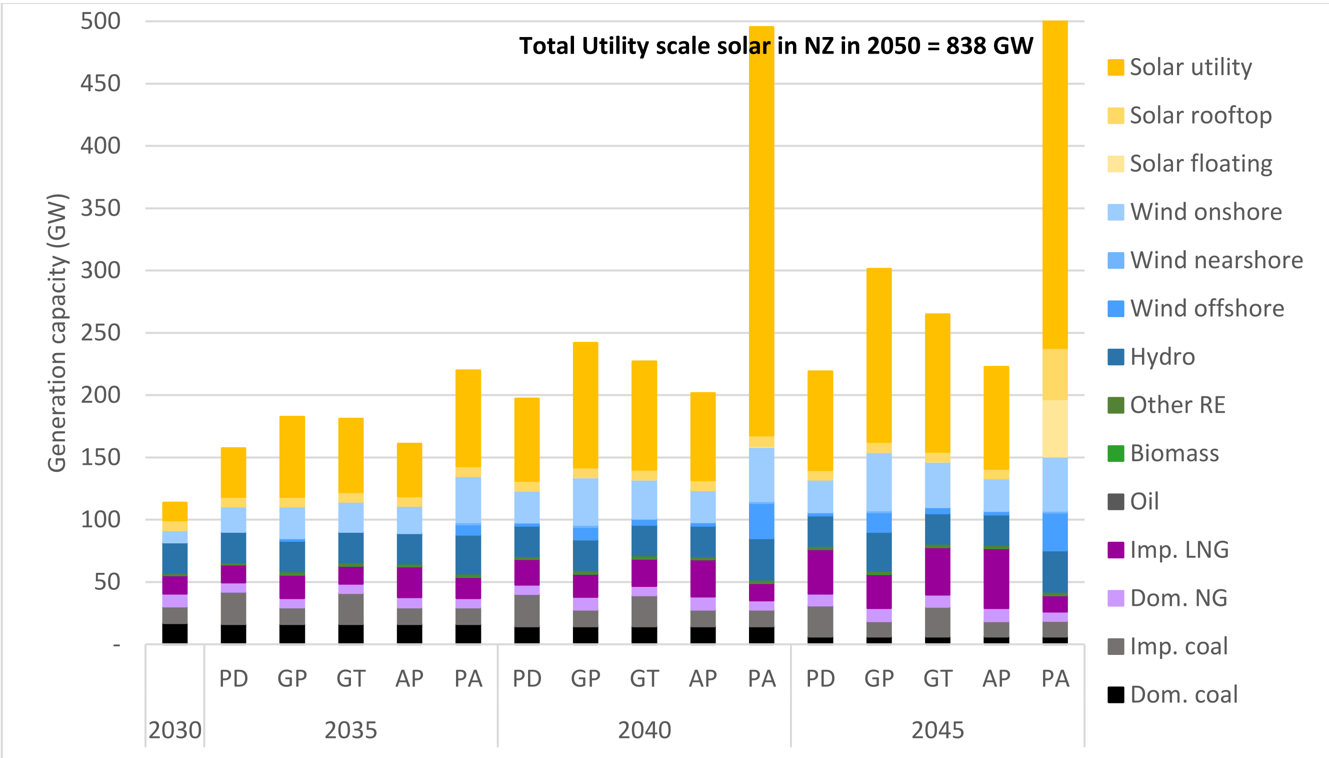


Figure 39: Generation capacity for the five main scenarios in 2020, 2030, 2040 and 2050. The y-axis has been cut off at 600 GW to allow for more detailed viewing, though the NZ total capacity lands at 1,166 GW (hidden capacity is solar).

Integration of wind and solar generation

Storages

All five main scenarios show considerable wind and solar generation in future years and a declining role for thermal generation in the electricity mix. The variable and intermittent nature of generation from technologies such as wind turbines and solar cells poses the challenge that power demand still needs to be met during wind-still nights, while at the same time the system needs to remain balanced during hours with high wind and solar output.

One measure for integrating variable renewable energy is the use of power storages such as batteries and pumped hydro. In Balmorel, investments can be made in specific, fully defined pumped hydro projects or in lithium-ion batteries, which can be optimized independently in storage volume and inverter capacity. Table 11 shows the resulting sizes of both batteries and pumped hydro for three scenarios with increasing wind and solar generation.

		Batteries			Pumped hydro		
		Inverter capacity (GW)	Storage volume (GWh)	C-ratio	Pump/Turbine Capacity (GW)	Storage volume (GWh)	C-ratio
2035	**BSL**	-	-	-	1.2	10	8.66
	GP	0.8	2	2.51	1.2	10	8.66
	NZ	4.4	11	2.51	1.2	10	8.66
2040	**BSL**	3.3	9	2.73	1.2	10	8.66
	GP	9.9	26	2.62	2.7	23	8.67
	NZ	140.1	678	4.84	8.9	83	9.33
2045	**BSL**	6.3	17	2.73	1,2	10	8.66
	GP	20.8	59	2.83	6.0	59	9.81
	NZ	331.1	1,619	4.89	8.9	83	9.33
2050	**BSL**	24.7	68	2.75	1.2	10	8.66
	GP	80.1	281	3.51	6.0	59	9.81
	NZ	457.5	2.324	5.08	8.9	83	9.33

Table 11: Storage and loading/generation capacity of batteries and pumped hydro, along with the C-ratio (storage volume divided by the generation capacity) for the BSL, GP and NZ scenarios

Increasing levels of wind and especially solar power require more storage for balancing. The optimized C-ratio of the batteries indicates that the power system requires relatively little storage volume compared to inverter capacity in circumstances of lower solar power penetration levels. Only needing to cover balance the system in few hours. However, when the total solar and wind generation increases, more storage is needed to move generation over longer periods of time. At this stage, pumped hydro with a fixed large storage volume per turbine capacity also becomes more attractive.

Transmission

As wind and solar resources are highly location-dependent, capacity build-out is larger is some regions than in others. This can be seen in Figure 40, where the generation is shown for the *GP* scenario for 2040 and 2050. While the Northern regions have relatively lower variable generation, South Central produces the majority of the offshore wind generation, the Southeast region has the larger solar production and the South West region is dominated by onshore wind generation. The graph also shows that wind and solar power is not necessarily produced where it is needed and thus needs to be transmitted to the demand centres.

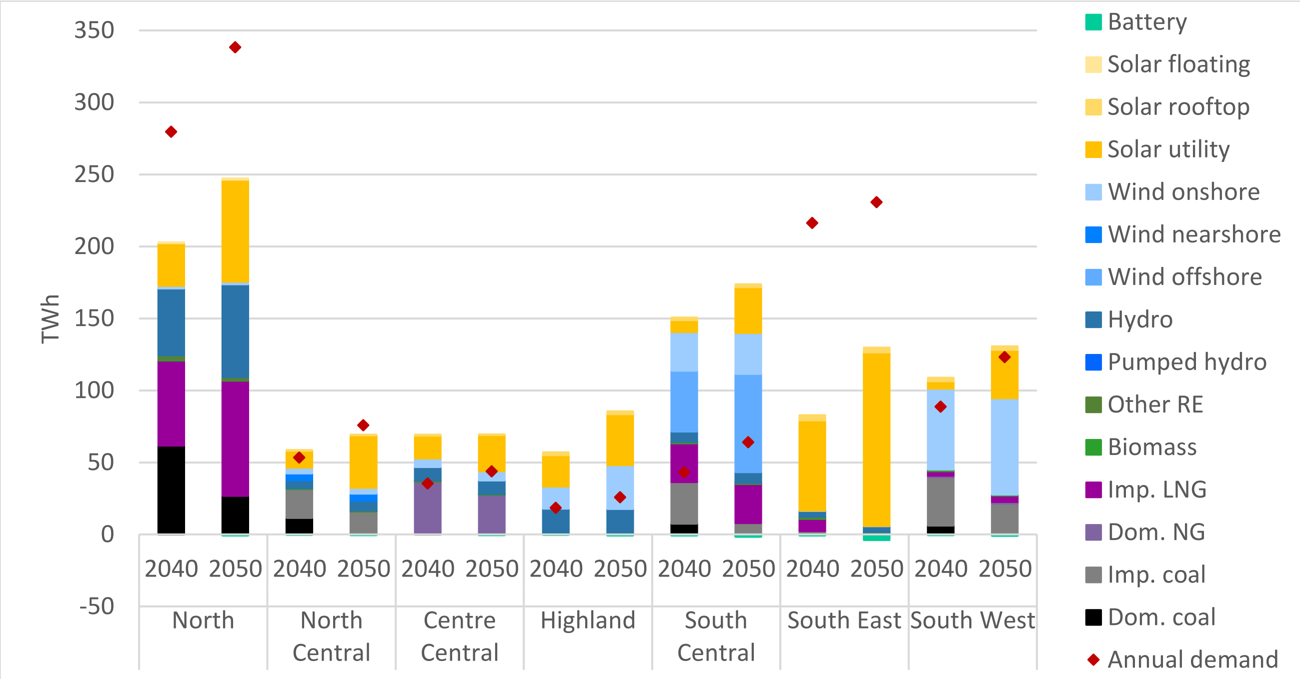


Figure 40: Annual generation and demand in the GP scenario for 2040 and 2050 shown per region.

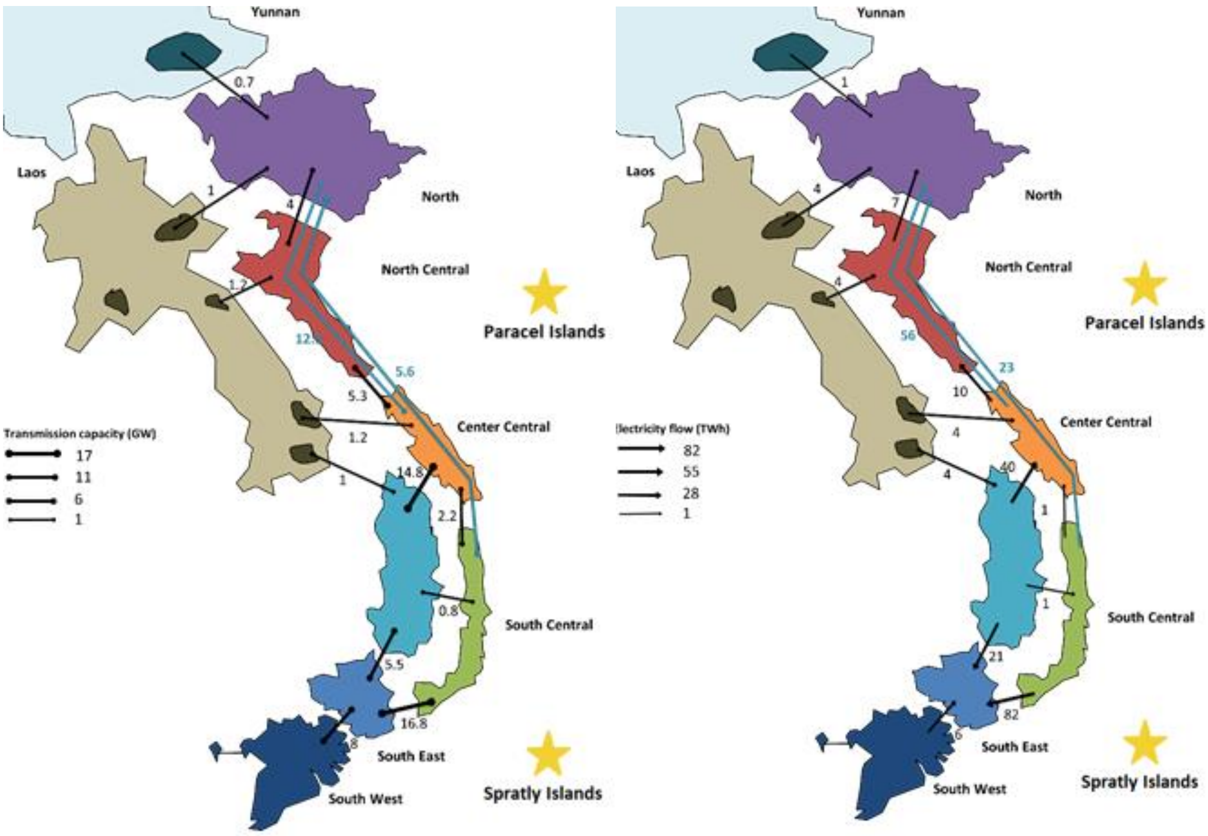


Figure 41: Transmission capacity and net annual transmission between regions in 2050 for the GP scenario. Turquoise lines are HVDC

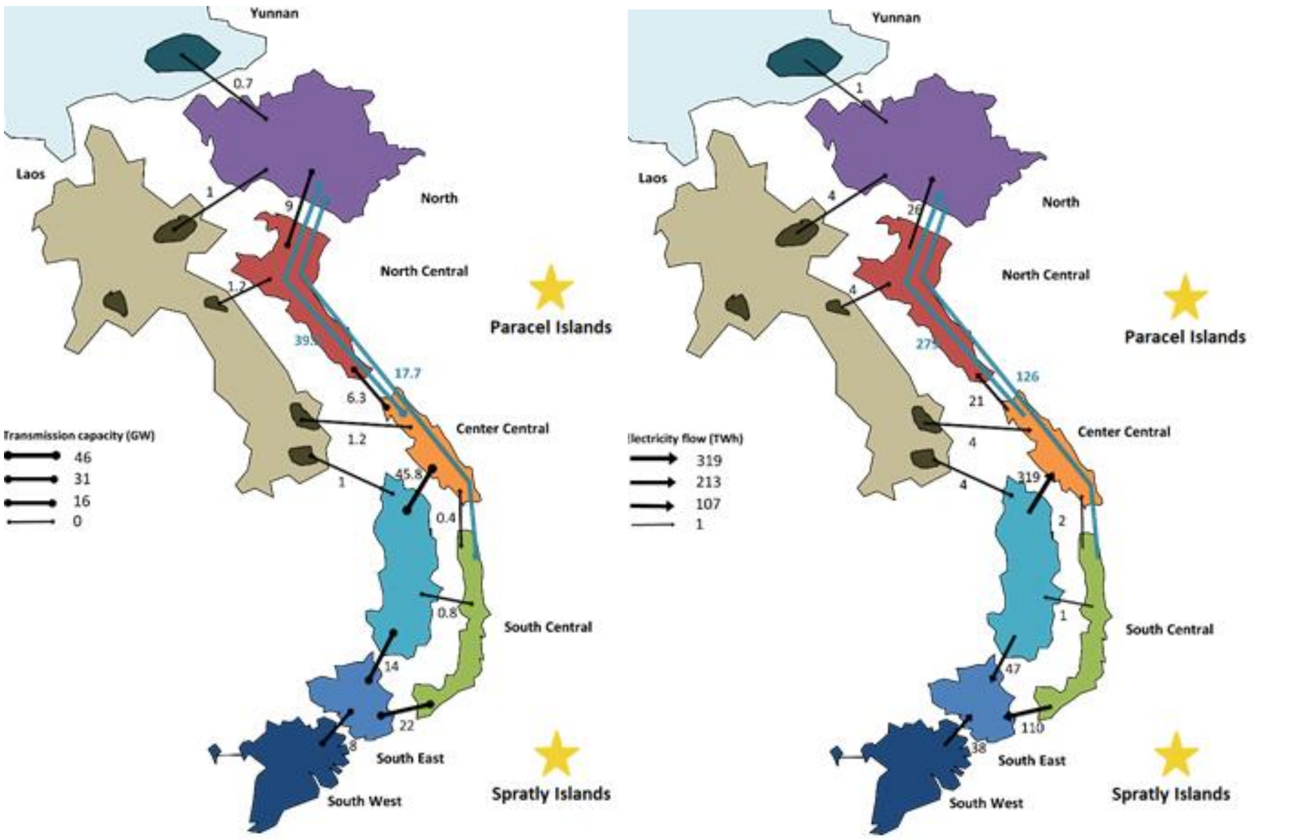


Figure 42: Transmission capacity and net annual transmission between regions in 2050 for the NZ scenario. Turquoise lines are HVDC

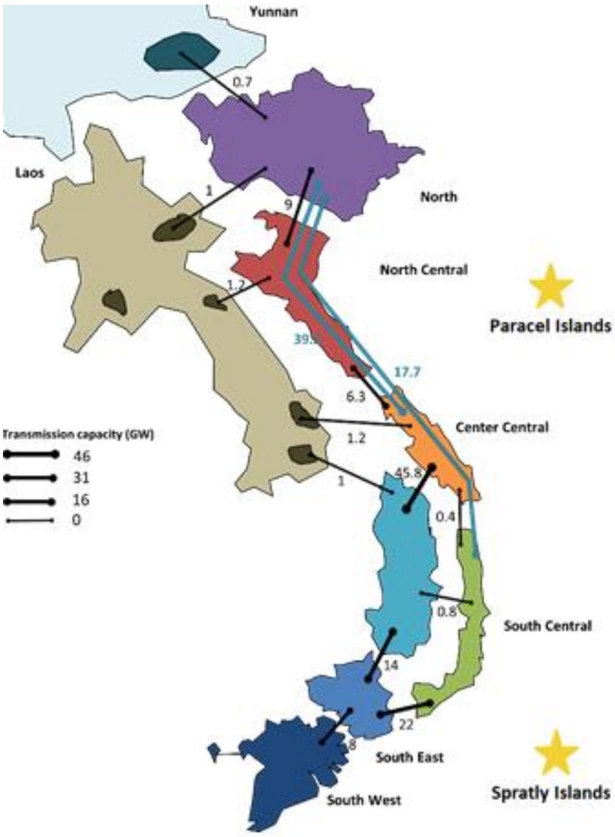


Figure 41 and

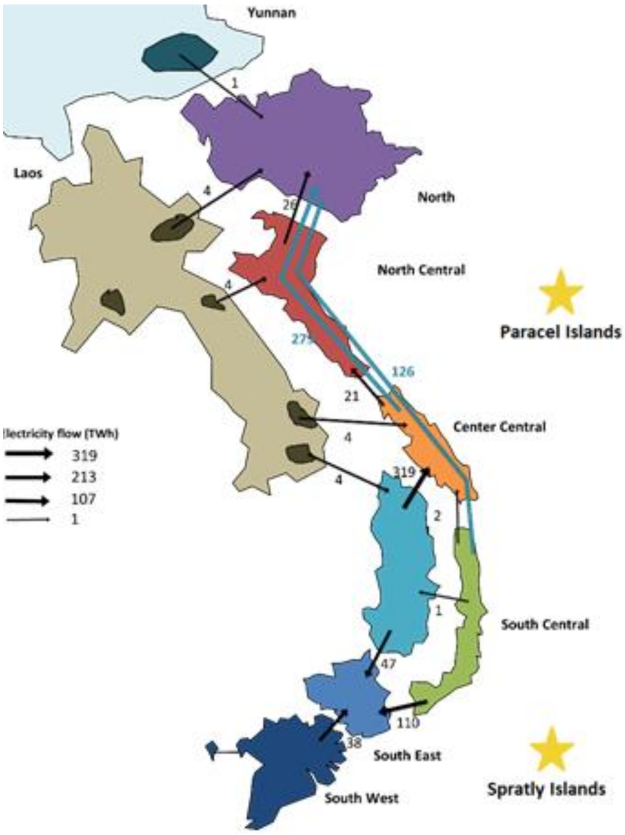


Figure 42 show the transmission capacity and transmission flows in 2050 for the *GP* and *NZ* scenario respectively. It can be seen that both the North region and the South East region import large amounts of electricity from South Central and Highlands. To accommodate the transmission from the South of Viet Nam to the Northern regions, large investments in cross-country HVDC lines are seen. The relation between large VRE build-out and the need for transmission capacity can be seen in Figure 43, where the more ambitious scenarios show a larger expansion in transmission capacity.

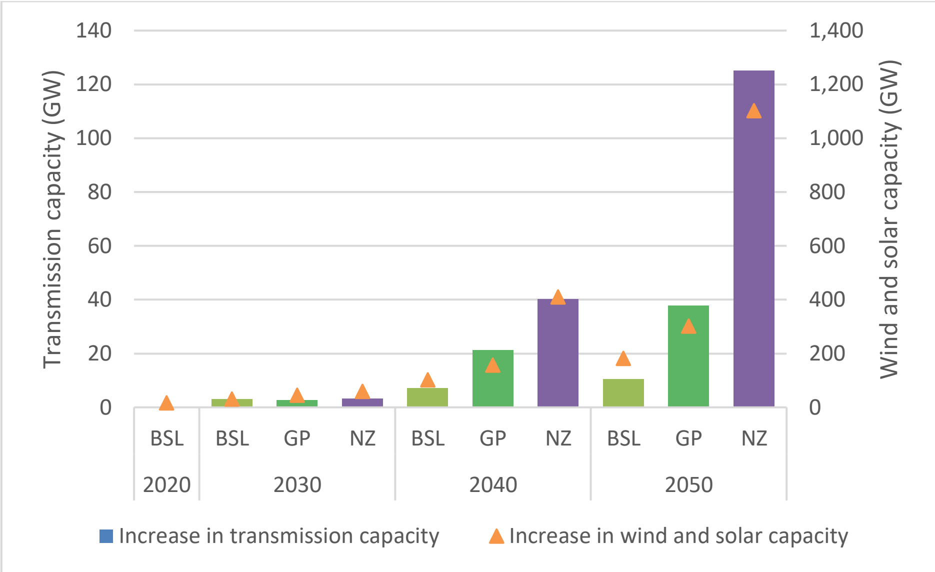


Figure 43: Increase in transmission capacity (left) and wind and solar capacity (right) in 2030, 2040 and 2050 compared to 2020 for Viet Nam for the BSL, GP, and NZ scenarios

Full load hours (FLHs) of coal fired power plants and gas fired power plants:

In scenarios BSL, GP, GT, and AP, coal and gas power plants with BOT investment form will be set with minimum FLHs in the model to 6000 hours/year, minimum FLHs of coal thermal power plants and CCGTs are set to about 4000 hours/years. In the results coal and gas power plants have the FLHs about 4000-6500 hours/year. Only in NZ scenario, the minimum of full load hours of coal and gas fired power plants are not set in the model from 2030, so the FLHs will begin to reduce from 2030 (imported coal have FLHs about 2500 hours in 2030), only achieve about 600-2000 hours/year in 2040, and reach Zero in 2050. In 2050, there will be about 27 GW installed capacity of coal and gas in NZ scenario (due to the project life is not over), but they will not generate any energy.

Dependence on imported fuels

Increased RE generation in the power system has also beneficial effects on the Vietnamese dependency on imported fuels. Figure 44 reveals that scenarios with higher RE shares increase independence both in absolute and relative terms. Where the *BSL* scenario consistently has about 25-30% of total costs in imported fuels, the *GP* and *NZ* scenario see this share reduced to below 12% and 0% respectively.

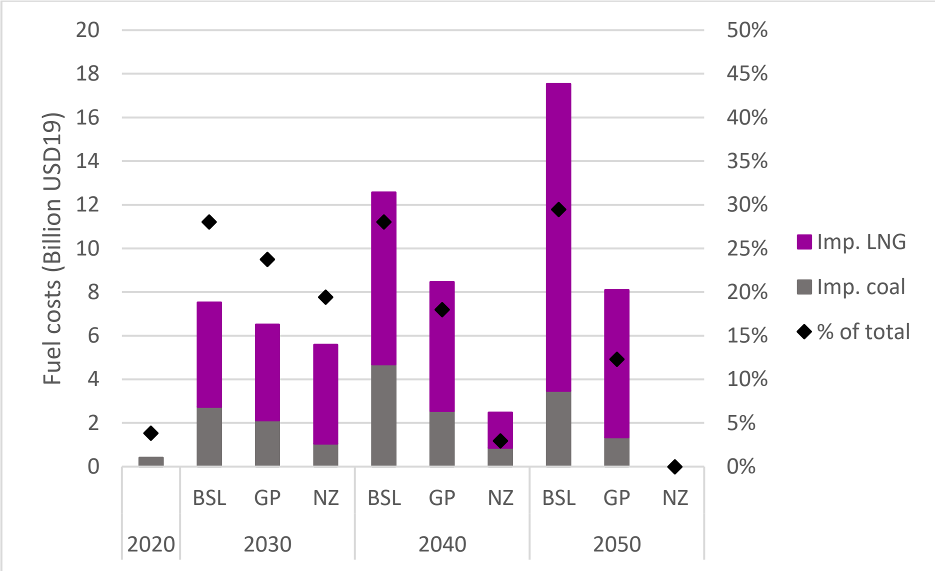


Figure 44: Fuel costs of imported fuels and their share of total system costs for the BSL, GP *and* NZ *scenarios in 2020, 2030, 2040 and 2050*

Emissions and pollutants

CO_2 emissions

One of the large drivers for the green transition underlying the assumptions of some of the scenarios is the goal to limit climate change by reducing carbon emissions. The model restrictions to achieve this transition range from RE requirements in the *GP* and *GT* scenarios to direct CO_2 limits in the *NZ* scenario. While the *AP* scenario in essence is not concerned with carbon emissions, results show that efforts to reduce pollutants has a direct effect on CO_2 emitted as well.

Figure 45 shows carbon emissions in the power system for the different scenarios. For 2030, the main differences are seen for the *GP* scenario with a small drop and in the *NZ* scenario where emission decrease with 23%. This shows that to reach zero emissions in the power sector by 2050, action needs to be taken already in the coming decade.

From 2040, differences between scenarios are more pronounced. The *GP* scenario emits about 65% to half compared to the *BSL* scenario in 2040 and 2050 respectively and the *NZ* scenario sees rapid reductions to reach zero emissions in 2050. The *GT* scenario also sees modest reductions in emissions, taking advantage of the increased flexibility from EVs to reduce fossil fuel consumption.

The *AP* scenario also shows significantly lower carbon emitted (about 15% by 2050) compared to *BSL*.

All scenarios but the *GP* and *NZ* scenario, see the carbon emissions' peak in 2040. The *NZ* scenario is the only scenario where emissions decrease below 2020 levels (to 50% in 2040 and zero emissions in 2050).

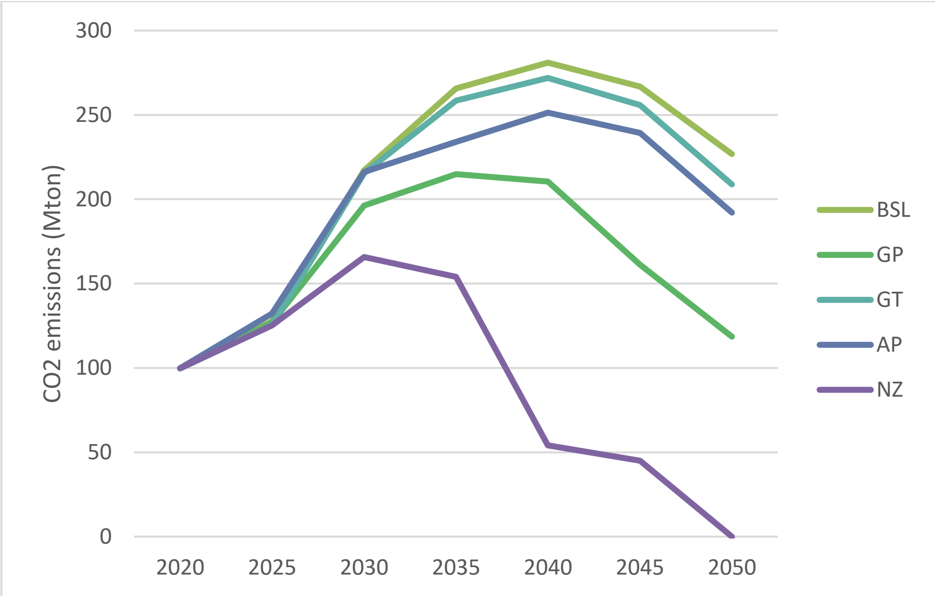


Figure 45 CO_2 emissions in the power system *for the five main scenarios in 2020, 2030, 2040 and 2050.*

Pollution

Apart from CO_2 emissions and its related global consequences, monitoring and reducing the emissions of pollutants in Viet Nam is also very relevant to ensure its inhabitants health and reduce the health costs incurred because of pollution.

In the *AP* scenario, the pollutants' health costs are explicitly included in the optimization of the power sector, resulting in large reductions compared to the *BSL* scenario up to 54% by 2050. It is, however, not the only scenario in which pollutants are reduced. Other green scenarios such as the *GP* and especially the *NZ* scenario show stark reductions as seen in Figure 46.

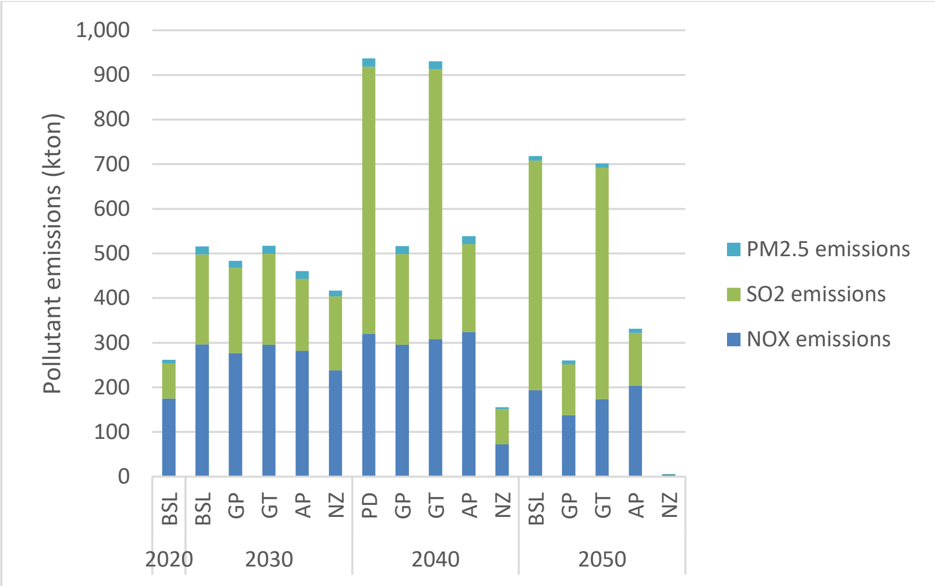


Figure 46 Pollutant emissions in the power sector for the five main scenarios in 2020, 2030, 2040 and 2050.

Power system costs

Previous sections described some positive consequences of more ambitious scenarios for the Vietnamese power sector. In this section, the costs of those ambitions will be quantified. It should be noted that the size of the power sector differs across scenarios, mostly so for the *NZ* scenario compared to the others (see Figure 39). Therefore, the system costs of the scenarios will be compared per unit of power consumption.

Figure 47 shows this relative system costs for the five main scenarios as well as the relative carbon emissions. Comparing the *GP*, *GT* and *AP* scenarios to the *BSL* scenario, shows that relatively big reductions in the CO_2 emissions (up to 48% in 2050) can be achieved without very large increases in costs, which range from +9% in the *GP* scenario to virtually no increase in the *AP* scenario if considering the pollution costs. When larger emissions costs are made in the power sector, costs rise significantly. This can be seen in the *NZ* scenario where a net zero scenario raises the costs per unit of demand with 42% in 2050. Summary of the relative changes compared to the *BSL* scenario can be seen in Table 12.

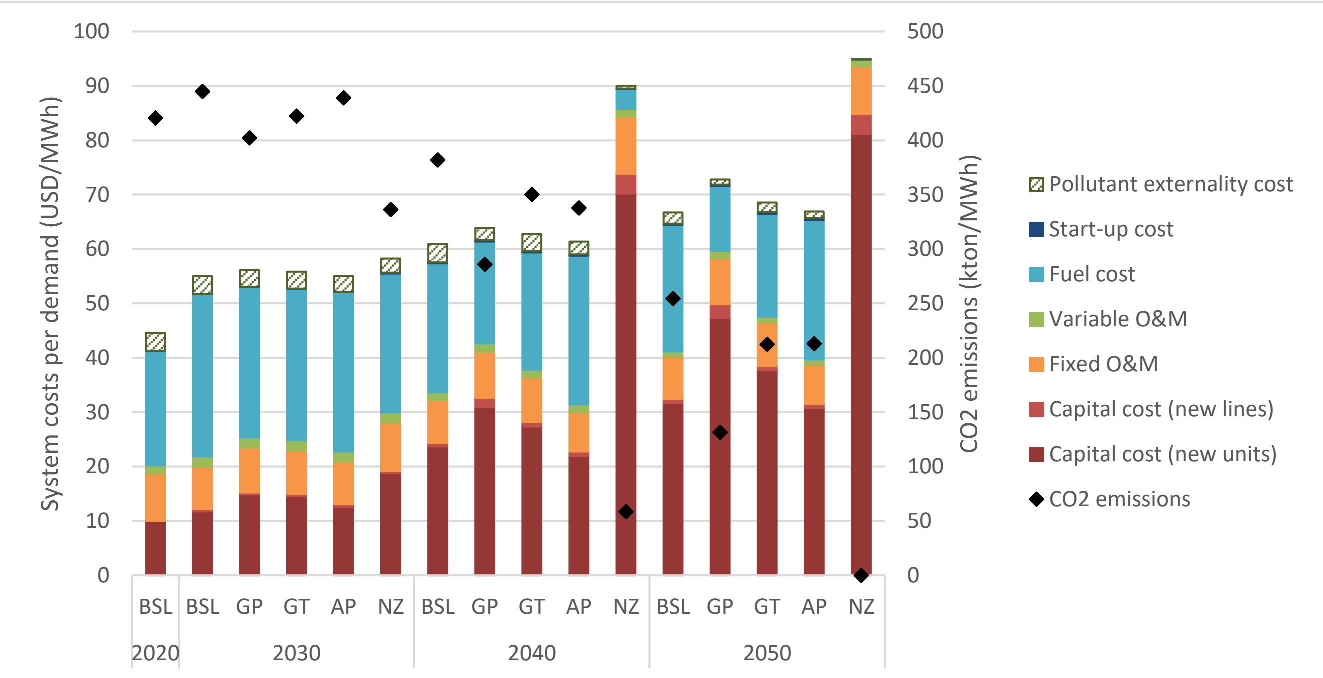


Figure 47 System cost per unit of power consumption for the five main scenarios in 2020, 2030, 2040 and 2050.

		Change compared to *BSL* scenario	
		CO_2 emission per demand reduction	System cost per demand increase
GP	**2020**	0%	0%
	2025	1%	0%
	2030	10%	2%
	2035	19%	1%
	2040	25%	5%
	2045	40%	9%
	2050	48%	9%
GT	**2020**	0%	0%
	2025	4%	1%
	2030	5%	1%
	2035	8%	2%
	2040	8%	3%
	2045	11%	3%
	2050	17%	3%
AP	**2020**	0%	0%
	2025	-2%	-1%
	2030	1%	0%
	2035	13%	0%
	2040	12%	1%
	2045	12%	1%
	2050	16%	0%
NZ	**2020**	0%	0%
	2025	2%	1%
	2030	24%	6%
	2035	44%	12%
	2040	85%	48%
	2045	90%	57%
	2050	100%	42%

Table 12 Changes in CO_2 emissions and system costs per unit of demand compared to the BSL scenario for the GP, GT, AP and NZ scenarios.

Linked data between Balmorel and PSS/E

The PSS/E grid detailed study is implemented based on Balmorel result of BSL scenario in 2025 for mid-term period and 2035 for long-term period. The result from Balmorel model will provide 2 important inputs to PSS/E model including:

- ***The installed generation capacity and installed transmission capacity*** between regions in each calculation years. The power plants in each region and the inter-regional transmission system in PSS/E will be built based on this input from Balmorel.
    - Generation capacity: Based on input data from Balmorel for BSL scenario, there are 241 power plants in Viet Nam power system in 2025 and increase to 295 power plants in 2035 (some large power plants are divided into each unit and renewable

energy source such as solar, wind, and biomass are divided into each region)

- The inter-regional transmission system: will be built based on installed transmission capacity between region from Balmorel.

FromRegion	ToRegion	Invested transmission capacity (MW) 2020	2025	2035	Installed transmission capacity (MW) 2020	2025	2035
North	North_Central				2,400	4,000	4,000
	Center_Central			1,278			1,278
North_Central	North				2,400	4,000	4,000
	Center_Central			1,874	3,500	3,500	5,374
Center_Central	North			1,278			1,278
	North_Central			1,874	1,400	1,400	3,274
	Highland				2,000	6,000	6,000
	South_Central				400	400	400
Highland	Center_Central				2,000	6,000	6,000
	South_Central				800	800	800
	South_East				4,000	5,500	5,500
South_Central	Center_Central				400	400	400
	Highland				800	800	800
	South_East				8,000	10,000	10,000
South_East	Highland				4,000	5,500	5,500
	South_Central				3,500	4,500	4,500
	South_West				7,960	7,960	7,960
South_West	South_East				7,960	7,960	7,960
Yunnan_Export_N	North				700	700	700
Laos_Export_N	North					972	1,032
Laos_Export_NC	North_Central					725	1,178
Laos_Export_CC	Center_Central				250	1,110	1,770
Laos_Export_H	Highland				322	602	998

Table 13 : Installed transmission capacity between regions from Balmorel in 2020 and 2035.

- ***The generation dispatch snapshots***: Balmorel optimizes the hourly output power of each power plant in each region and the loading level of the transmission lines, this is called "snapshot" and transfer to PSS/E model. The most critical dispatching hours are selected to be simulated in grid operation, in order to check the response of the transmission system. There are 7 snapshots chosen for BSL scenario as follow:
  - Highest generation (HG)
  - Lowest generation (LG)
  - Highest residual demand (HRD)
  - Lowest residual demand (LRD)
  - Maximum total interconnected transmission capacity (HF)
  - Minimum total interconnected transmission capacity (LF)
  - Highest wind and solar Curtailment (HC)

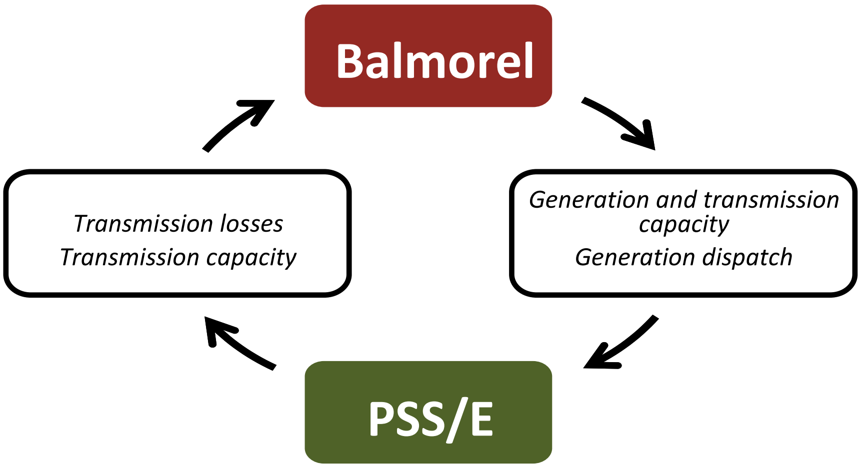


Figure 48. Methodology diagram of interaction between the Balmorel and PSS/E model

Detailed transmission system results

PSS/E simulation result in 2025

The grid simulation shows that the inter-regional transmission system corresponding to the output of Balmorel in 2025 met N-1 criteria, there is no overload or high/low voltage occur in 7 simulation regimes. That means the transmission capacity in Balmorel model in 2025 is suitable.

The simulation result shows that in 2025 the power system can maintain voltage quite good in allowance range, even in some very light load such as LG, LRD or HC.

However, the internal transmission regimes in general are not met the N-1 criteria, especially in demand supply grid, some critical elements are as follow:

- North: Thai Binh TPP – Thai Thuy 220 kV TL
- North Central: Vung Ang TPP – Vung Ang 220 kV TL
- Highland: Krong Buk 500 kV substation to Krong Buk 220 kV
- South Central: WPP Phu My – Phu My 220 kV TL
- Southeast: Nhon Trach – Nha Be, Nam Hiep Phuoc – CCGT Hiep Phuoc, Nam Hiep Phuoc – Phu My, Phu My – My Xuan 220 kV TL
- Southwest: Bac Lieu – Soc Trang 220 kV TL

This is consistent with the result of Investment plan of power transmission system in 2021 with vision to 2025 of National Power Transmission Corporation (NPT) prepared by Institute of Energy. In generally Viet Nam power transmission system does not completely meet N-1 criteria due to the difficulties in mobilizing investment capital.

Since the simulation shows that there is no overload in highest curtailment – HC snapshot, the reason for curtailing renewable energy in this regime is system-wide excess power. This regime is in Tet holiday in Viet Nam when the peak load much reduce to only 16 GW, account for 30% of Pmax year, so the model chooses to curtail renewable energy such as wind, solar and hydro to balancing power demand and source.

PSS/E simulation result in 2035

The transmission flow on the ***inter-regional grid*** in each regime is consistent with Balmorel output. The simulation result show that in 2035 the inter-regional transmission system operates safely and reliably, there is no overloading and the voltage is maintained in allowed range in both normal operation and N-1 fault regimes.

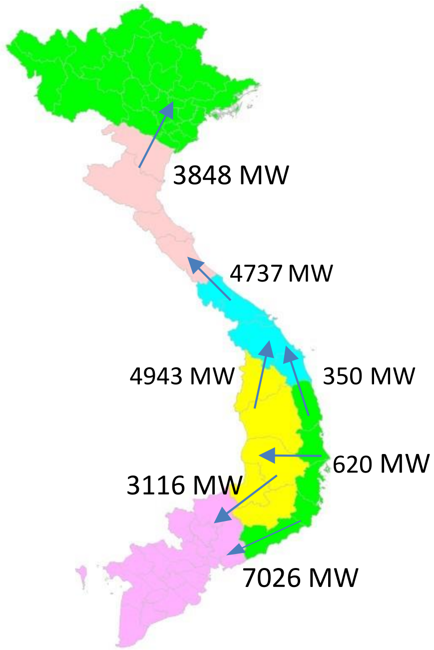


Figure 49: Transmission flow on the inter-regional grid in 2035 in HF snapshot - the map only shows the mainland

The following analysis will go deeply into the highest transmission flow snapshot HF:

- In the highest transmission flow regime, the interfaces carry load quite high from 60 – 80%. The interface with the highest inter-regional flow is South Central – Southeast with more than 7000 MW (loading 70%). The most critical element of this interface in N-1 fault regime is Vinh Tan – Dong Nai 2 500 kV TL and Hong Phong - Song May 500 kV TL with highest loading of 80%.
- The interface of Southwest to Southeast has the highest loading with 84%, mostly transmit capacity of O Mon gas power complex and Long

Phu coal thermal power complex. Like interface of South Central – Southeast, this interface has strong connection with 8 circuits of 500 kV TL, so the effect of N-1 fault is reduced with the most critical elements is My Tho – Phu Lam and Long An – Nha Be with highest loading is nearly 90% in the fault of each circuit.

- Other interfaces have smaller loading in normal operation condition and there is no overload in N-1 fault regimes. The node has the lowest voltage of inter-regional transmission system is Quang Trach and Vung Ang of interface Mid-Central – North Central with 497 kV (0.994 pu). This interface has the highest transmission distance of more than 300 km, so the voltage loss is also the highest. However, at the end point of Quang Trach and Vung Ang there is Quang Trang TPP and Vung Ang TPP can supply reactive power to maintain voltage in the allowed range.

The internal transmission system in 2035 is according to draft PDP8 since Balmorel model does not consider this. The different in power source development program between EOR 21 and PDP8 (draft) can cause some elements with overloading or low/high voltage in the internal transmission system.

The amount of N-1 contingency cases which result in other elements overloading are summarized for the 7 Balmorel snapshot as follows:

- HG: 43/921 cases (4.7%)
- LG: 7/921 cases (0.8%)
- HRD: 11/921 cases (1.2%)
- LRD: 29/921 cases (3.1%)
- HF: 36/921 cases (3.9%)
- LF: 9/921 cases (1%)
- HC: 22/921 cases (2.4%)

The results show that in 2035 HG is still the snapshot with the highest violation rate with 43 violations (4.7%). The second is HF with 36 violated cases and LRD with 29 cases, accounting for 3.9% and 3.1% respectively. In other snapshot, the N-1 criteria violations is 1-2%.

Based on calculation result of PSS/E of the element that is overload or voltage violation in normal operation and N-1 fault regimes, the study will propose the volume of transmission grid need to be built new/renovated to meet the operation requirement of Grid code.

Transmission loss is calculated according to the formula:

$$Transmission\ loss\ in\ interface\ k\ (\%) = Average\left(\frac{Transmission\ loss\ in\ interface\ k\ in\ year\ i}{Energy\ transmission\ in\ interface\ k\ in\ year\ i}\right).100$$

Since the result from PSS/E model shows only power losses in the inter-regional transmission system, energy transmission loss in interface k in year i is calculated approximately by power loss in Highest generation snapshot multiplied by experience factor Γ:

$$\Delta A_{year} = \Delta P_{Peak\ load} \times \Gamma$$

Where:

ΔA_{year}: Energy transmission loss in year i

$\Delta P_{Peak\ load}$: Power loss in peak load regime in year i

Γ: Equivalent maximum power loss time, (Γ=(0.124+Tmax/10000)2x8760)).

On each interface, it is assumed that the number of line circuits and conductor size are identical with the 500 kV lines designed from the input of the resulting power source development. The transmission distance between the two regions is approximated by the typical distance from the center of the power source in one region to the center of the load in the other.

Interface		Power loss (%) 2025	Power loss (%) 2035	Average power loss (%) (1)	Current power loss in Balmorel (2)	Difference (1) - (2)
North	North Central	1.74%	1.81%	1.77%	3.2%	-1.43%
North Central	Center Central	2.67%	3.45%	3.06%	3.6%	-0.55%
Center Central	Highland	1.36%	1.36%	1.36%	2.5%	-1.13%
Center Central	South Central	2.47%	2.47%	2.47%	3.8%	-1.30%
Highland	Southeast	2.36%	2.36%	2.36%	3.5%	-1.14%
South Central	Southeast	2.35%	2.35%	2.35%	3.0%	-0.65%
Highland	South Central	1.05%	1.05%	1.05%	2.4%	-1.33%
Southeast	Southwest	2.06%	2.06%	2.06%	3.2%	-1.14%

Table 14: Result of transmission loss in inter-regional grid

The results show that the calculated transmission loss value in PSS/E software differs from transmission loss value put initial into Balmorel model by about 0.6%-1.4% depending on the interface.

The study estimated total volume and cost of substation and transmission line of simulation transmission system (at 500 kV and 220 kV) for BSL scenario in EOR2021 in 2025 and 2035. The estimated total investment cost for the transmission grid in 2025 is about 31.8 billion USD and in 2035 is about 50.5 billion USD. Considering separately the inter-regional transmission system, detailed grid modelling in PSS/E show that the investment cost for inter-regional grid is quite consistent with Balmorel but is a little higher.

6 Modelling results – Sensitivity analyses

Sensitivity analyses in the energy sector

As mentioned in Chapter 4 , three sensitivity scenarios are analysed for the full energy sector, namely: Low discount rate, Low EE, BSL_Hidemand. The assumptions of sensitivity scenarios are expressed in Table 15**.**

Scenarios	Assumption
High Demand	High forecasted GDP growth rate will be used to calculate energy demand
Low discount rate	Social discount rate is set to 6.3%. Other assumptions are based on the BSL scenario
Low NOEE	The penetration potential of Energy Efficiency equipment is 50% as compared to BSL scenario

Table 15: Assumption of sensitivity scenarios for the energy sector

The result of the sensitivity scenarios will be analysed through the total primary energy, costs and CO_2 emissions.

Sensitivity analysis on primary energy supply

The primary energy supply of the sensitivity scenarios is all increased compared to the demand of BSL scenario – mainly on the fossil fuel supply as seen in Figure 50. Of the scenarios, the High demand scenario has the largest increase of both the energy supplied and the amount of fossil fuels in the mix.

Primary energy supply of High demand is higher than BSL with 9% in 2030, 15% in 2040 and 18% in 2050. In 2050, the increase in imported coal of High demand compared to BSL is nearly 28% while in contrast, natural gas is decreased with 33%.

The lower percentage of penetration of EE equipment in the Low EE scenario gives an increase of 5% in 2040 and 2050 in the total primary energy supply compared to the BSL scenario.

While the total amount of energy supply in the Low discount rate scenario is hardly affected compared to the BSL scenario, this scenario is the only scenario where the share of renewable energy is higher than in the BSL scenario. The share of renewable energy in the Low discount rate scenario is about 26% in 2040 and 31% in 2050.

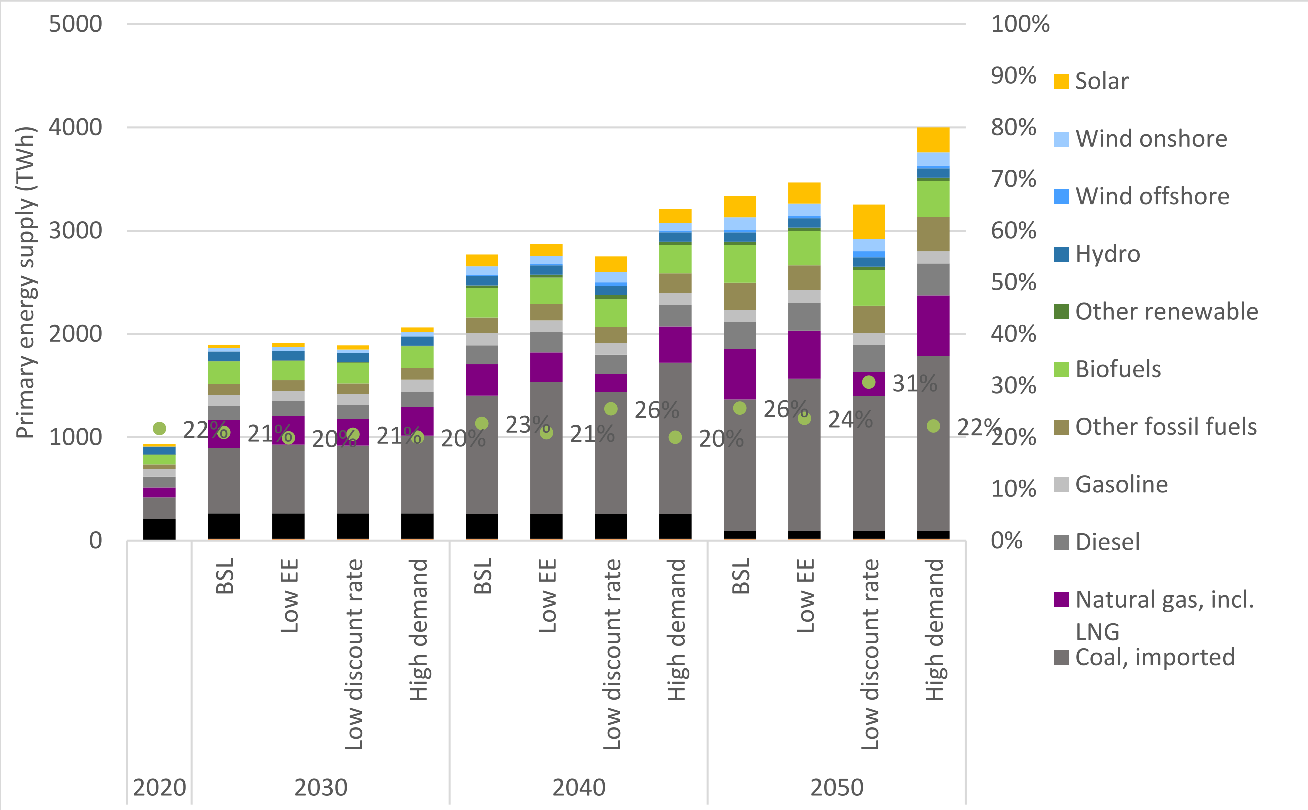


Figure 50: Total primary energy of sensitivity scenarios and BSL scenario

Total system costs

The total cost of the energy system in the High demand scenario increases significantly compared to BSL while the Low EE and Low discount rate scenarios has less significant changes.

The total cost of the High demand scenario is 13% higher than BSL in 2030 and more than 17% in 2050. The increase mainly comes from an increase of capital costs and fixed O&M costs. Due to the higher energy demand it also leads to higher air pollution costs – especially in 2050 where the air pollution costs rise with over 25%.

In the Low EE scenario, investment costs are around 18% higher than BSL in 2030, and this gap is narrowed to 2.3% in 2050. Corresponding with investment costs, O&M costs also increase. When there is a low penetration of EE the fuel costs show to decrease compared to BSL – indicating that in this scenario, technologies using cheaper fuels are chosen. This also influences air pollution costs which are higher than BSL.

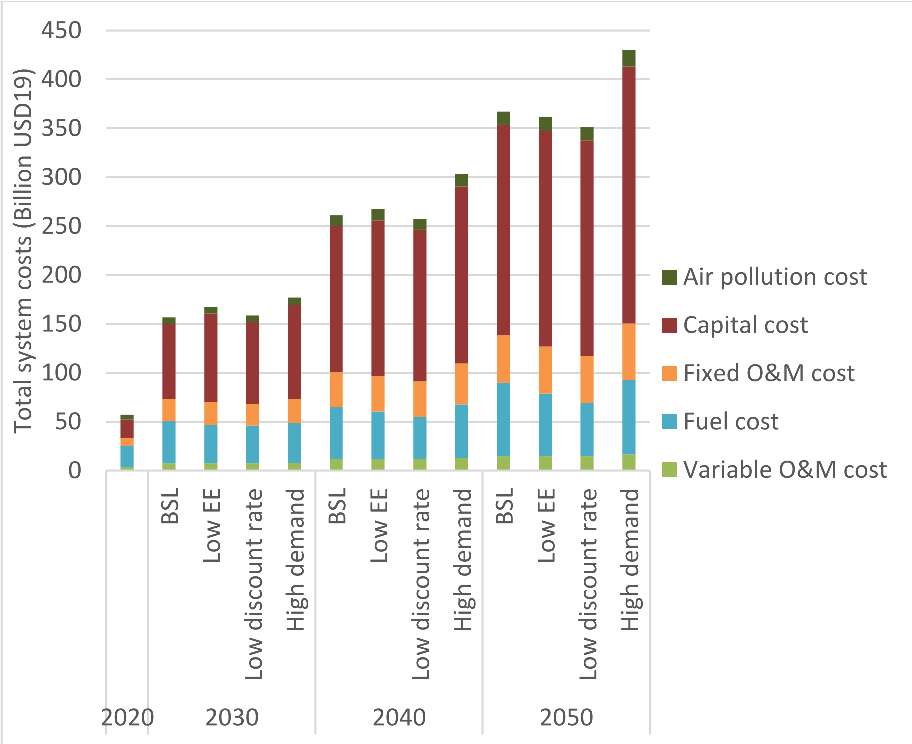


Figure 51: The cost of energy system of BSL and sensitivity scenarios.

CO_2 emissions

The CO_2 emissions from the energy system shows to be very much in line with the RE-shares. In Figure 52, the CO_2 emissions for the scenarios are shown, and the Low discount rate scenario shows to be the only scenario with a decrease in emissions.

In the High demand scenario, CO_2 emissions are 12% higher than BSL in 2030, 20% in 2040, and about 26 % in 2050, corresponding to 52 $MtCO_2$, 135 $MtCO_2$, and 197 $MtCO_2$ respectively.

With lower penetration of EE equipment, the CO_2 emissions increase more than 2% in 2030, 6% in 2040, and about 8% in 2050, corresponding to 13 $MtCO_2$, 45 $MtCO_2$ and 61 $MtCO_2$ respectively.

With the lower social discount rate, the CO_2 emissions are 2% lower in 2040 and 6% in 2050, corresponding to 15 $MtCO_2$, and 45 $MtCO_2$, respectively.

When considering the sectors, it shows that the main effected sectors are the industrial and the power sector, whose emissions are both increased for the High demand and Low EE scenario. When considering a lower discount rate, the emissions from industry are almost consistent with the ones from BSL, while the power sector emissions have been further reduced.

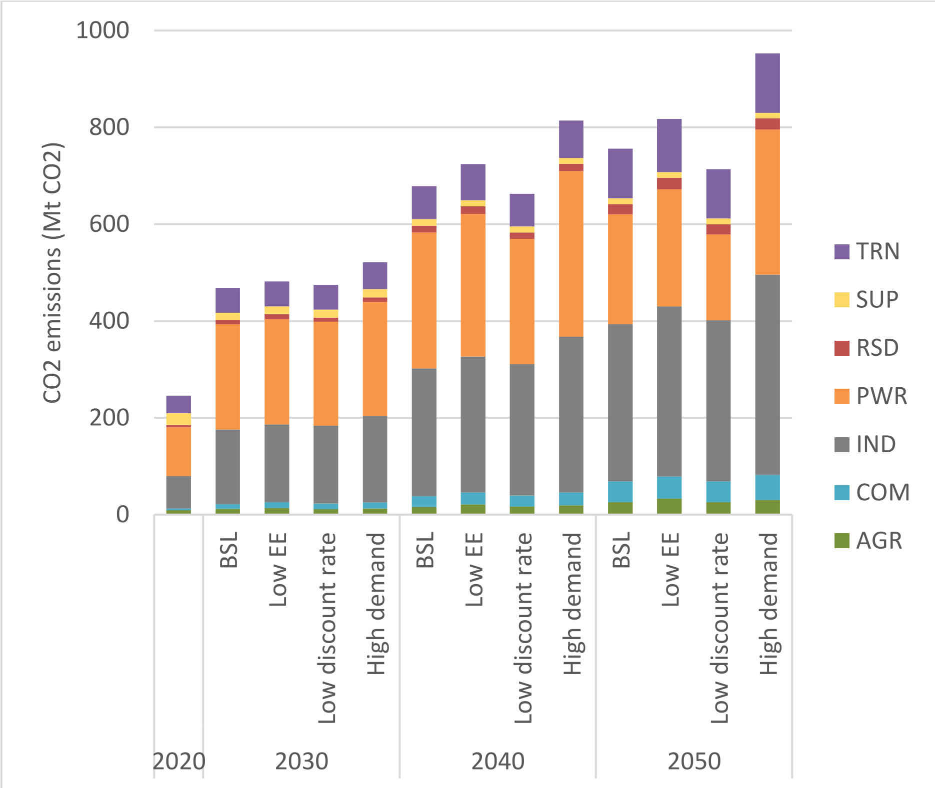


Figure 52: CO_2 emission by sector of sensitivity scenario and BSL.

Figure 52 expresses that higher demand and lower penetration of EE equipment result in higher CO_2 emission, in contrast, the lower discount rate tends to make emissions lower.

In the High demand scenario, CO_2 emission is higher than BSL about 12% in 2030, 20% in 2040, and about 26 % in 2050 respectively 52 $MtCO_2$, 135 $MtCO_2$, and 197 $MtCO_2$.

In the Low EE scenario, the CO_2 emission increase more than 2% in 2030, 6% in 2040, and about 8% in 2050 respectively 13 $MtCO_2$, 45 $MtCO_2$ and 61 $MtCO_2$.

With the lower social discount rate, the CO_2 emission is lower about 2,3% in 2040 and 5,56% in 2050 respectively about 15 $MtCO_2$, and 45 $MtCO_2$.

Sensitivity analyses in power sector

From assumptions of Baseline scenario, five sensitivity scenarios in power sector are analysed, include: Low discount rate, Low EE, High Demand, High LNG price, Low LNG price. Two sensitivity scenarios are based on Net-Zero scenario, include: High battery cost, Low solar potential. The assumptions of sensitivity scenarios are included in Table 16.

Scenarios	Assumption
Low Discount Rate	Social discount rate: 6.3%. Power demand and Bioenergy using for power sector from TIMES model
Low EE	Only 50% penetration of energy efficiency as compared to BSL scenario. Power demand and Bioenergy using for power sector from TIMES model
High Demand	High forecasted GDP growth rate will be used to calculate energy demand in TIMES model. Power demand and Bioenergy using for power sector from TIMES model
High LNG price	Prices of LNG are higher than base case 20%
Low LNG price	Prices of LNG are according to the Sustainable development scenario in Fuel projection report.
High battery cost	High cost of battery in Vietnamese Technology Catalogue 2021 (EREA and DEA, 2021b). The investment cost is set to 0,40 million USD-19 per MWh instead of 0,16 million USD-19 per MWh in 2050. This is approximately a150% increase in investment cost.
Low Solar Potential	Only a half of total solar technical potential can be implemented

Table 16: Sensitivity scenarios in power sector.

Sensitivity scenarios with different power demand result from TIMES

With lower discount rate, total power demand is a little higher than BSL scenario, but the demand of EV increase 5 TWh in 2030 and 10 TWh in 2050, demand for industry reduce for instead

In Low EE scenario, total power demand is also small higher than BSL scenario, but the demand of EV decrease about 10 TWh in 2050, demand of residential and industry increase for instead

With high forecasted GDP growth rate, total power demand is higher than BSL scenario about 10% in 2030 and 18% in 2050, demand increase in all sectors.

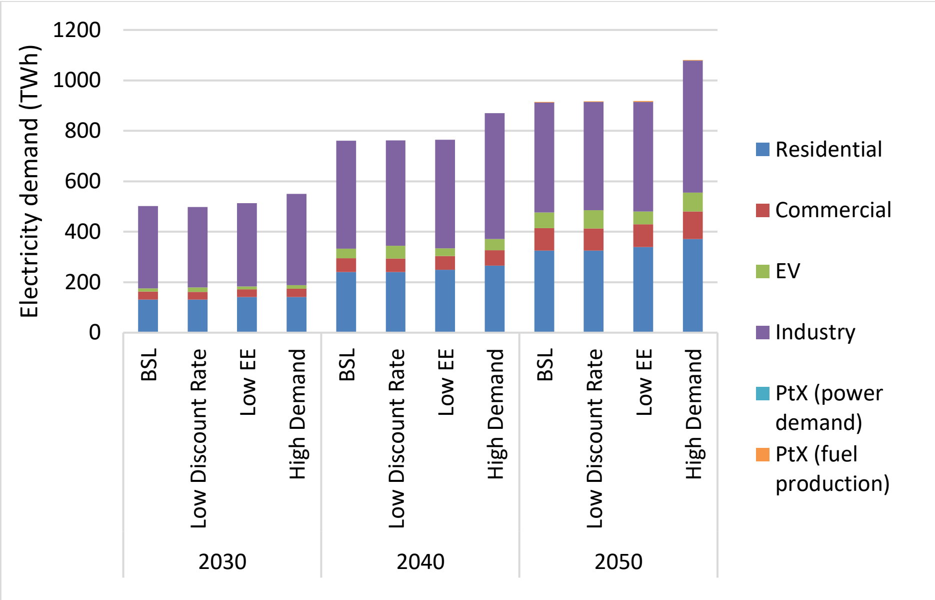


Figure 53: Different electricity demand of sensitivity scenarios from TIMES

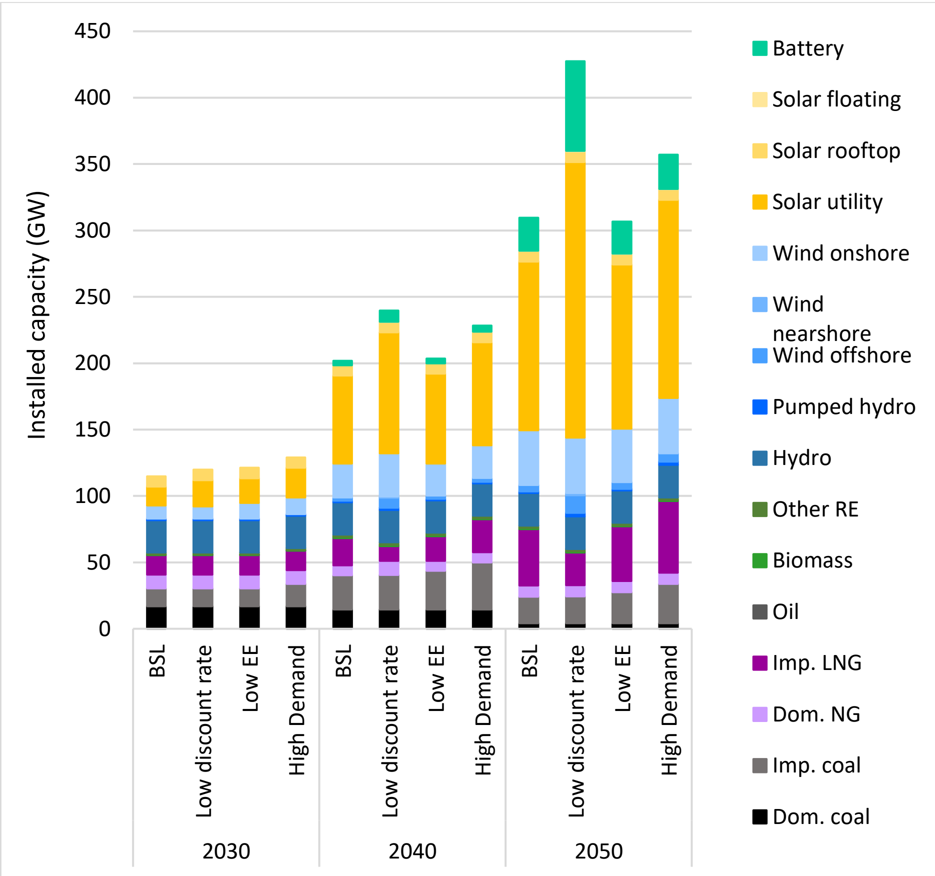


Figure 54: Installed capacity in sensitivity scenarios with different power demand from TIMES (exclude import from neighbouring countries)

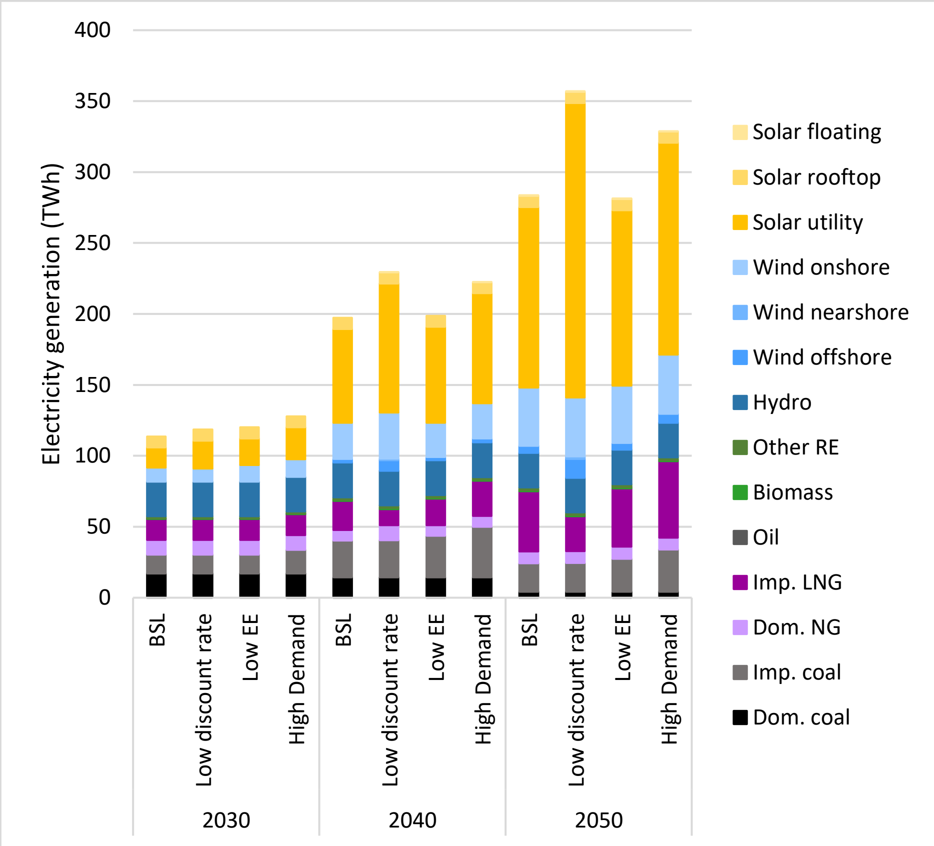


Figure 55: Electricity generation energy in sensitivity scenarios with different power demand from TIMES (exclude import from neighbouring countries)

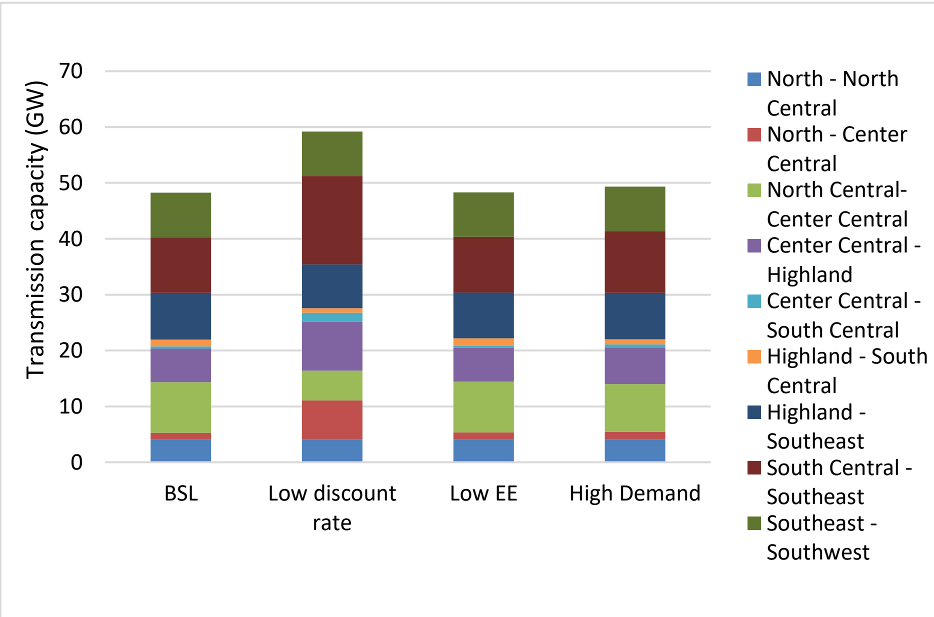


Figure 56: Regional transmission capacity of sensitivity scenarios with different power demand from TIMES in 2050.

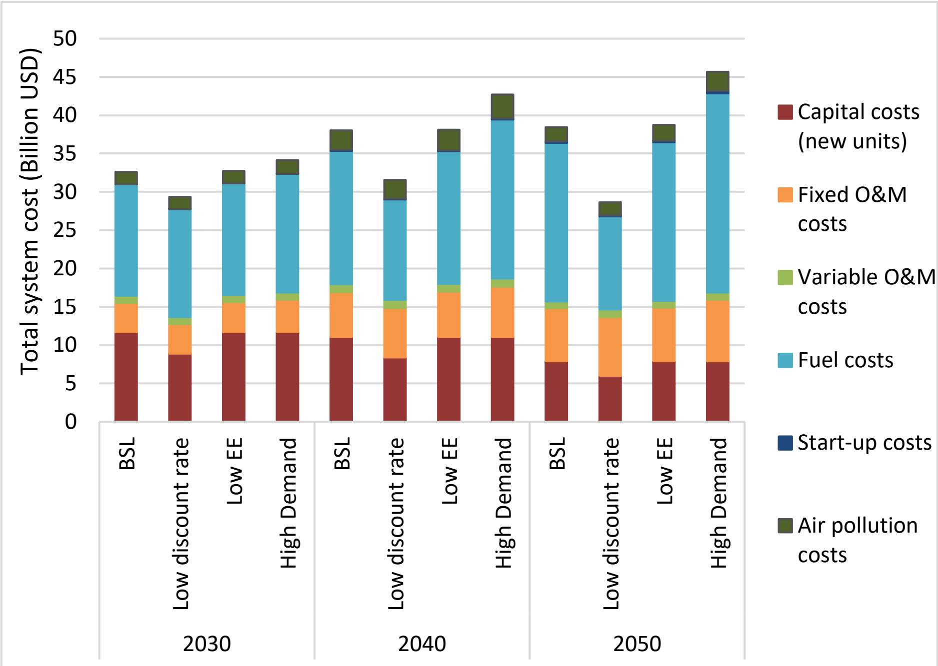


Figure 57: Power system cost of sensitivity scenarios with different power demand from TIMES.

Sensitivity assumption is not affected much in the result of installed capacity and generation in 2030 (except High Demand scenario), that is due to the exogenous capacity of firm-built projects. But in 2050, installed capacity of each generation types will change significantly comparing with the BSL scenario, specifically:

- With Low social discount rate, compared with BSL scenario, in 2050 LNG reduce about 19 GW, while offshore wind and nearshore wind increase 10 GW, solar PV increase 80 GW, battery and PHS increase 55 GW. Variable renewable energy (solar and wind) will be developmental priority with lower social discount rate. In 2050, the generation energy proportion of RE will be much over target (reach 66% in 2050 while the RE target is setup about 43%). Combo solar and battery will continue be competitive with other RE generation types in Low discount rate scenario. Region transmission capacity increase 11 GW, in which the capacity of interface South Central to Southeast increased 5.8 GW due to increasing offshore wind. Low discount rate scenario has total system cost is lower than BSL scenario about 8.6 billion USD in year 2050 (reduce 12% comparing with BSL scenario) because of reducing investment cost (include IDC) of all generation technology.

- In Low EE scenario, imported coal is higher 3.4 GW than BSL scenario, LNG reduce 1.3 GW and solar PV reduce 3.4 GW in 2050. The transmission capacity and total system cost of Low EE scenario are a little higher than BSL scenario
- With higher demand of High Demand scenario, in 2030 imported coal increase 3.4 GW, wind onshore increase 3 GW and solar PV increase 8.1 GW. In 2050, imported coal is higher 10 GW than BSL scenario, LNG increase 11.5 GW, wind offshore increase 1.5 GW and solar PV increase 22 GW, battery increase 1 GW. Transmission capacity is similar with BSL scenario. Total system cost is higher than BSL scenario about 13% in 2030 and 19% in 2050.

Sensitivity about LNG fuel price

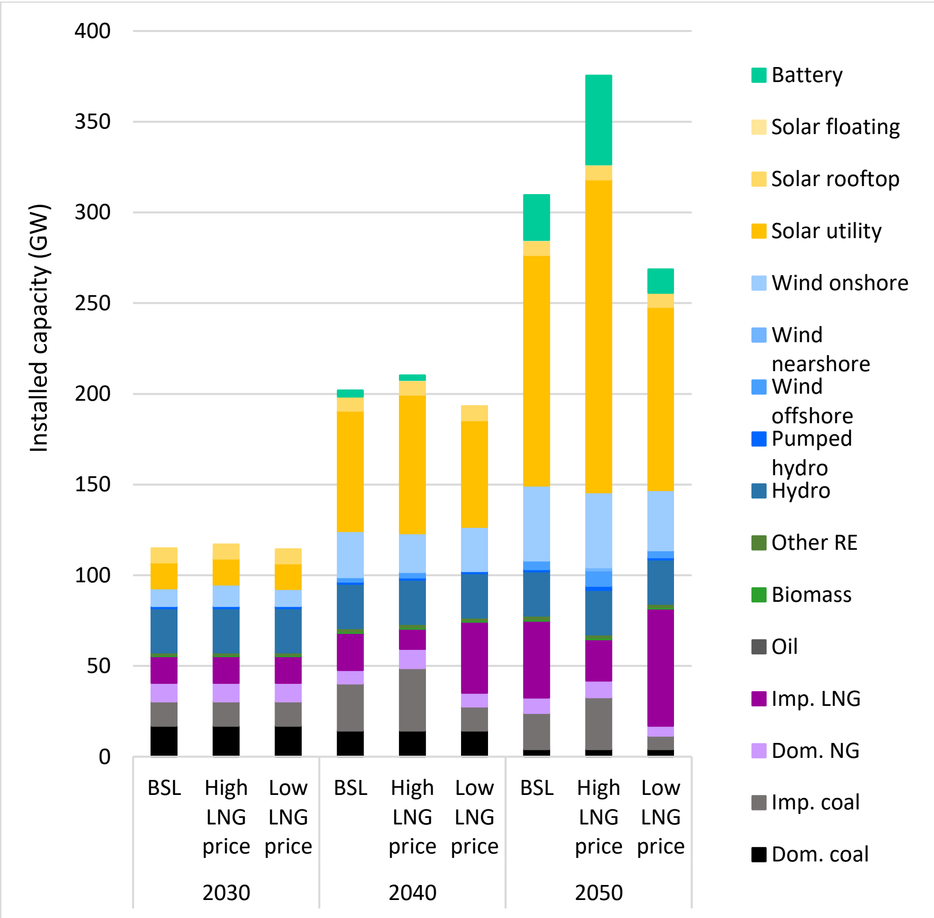


Figure 58: Installed capacity in sensitivity scenarios about LNG price (exclude import from neighbouring countries)

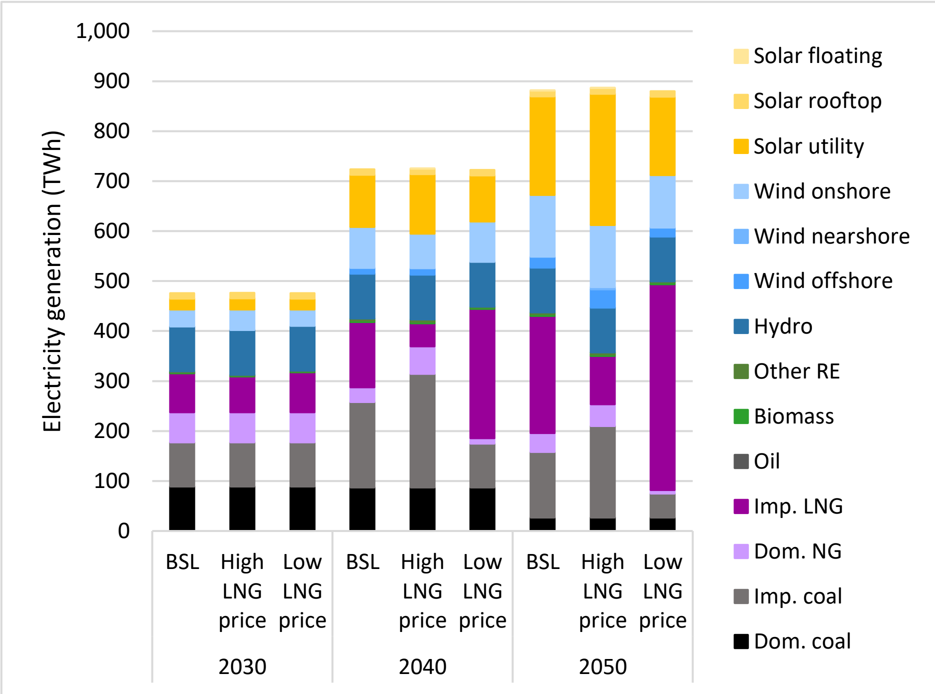


Figure 59: Electricity generation energy in sensitivity scenarios about LNG price (exclude import from neighbouring countries)

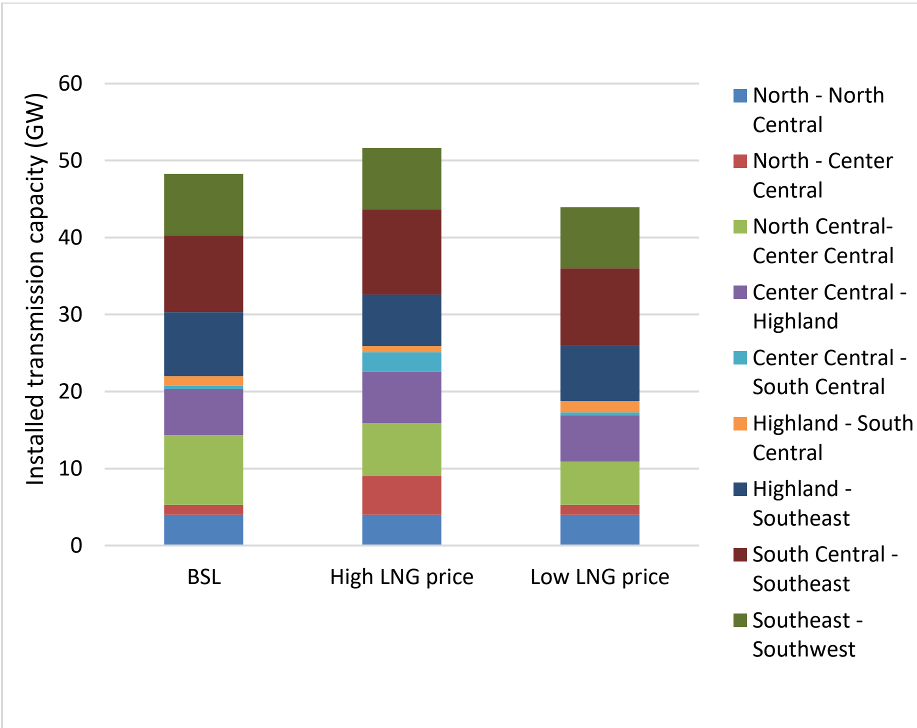


Figure 60: Regional transmission capacity of sensitivity scenarios about LNG price in 2050.

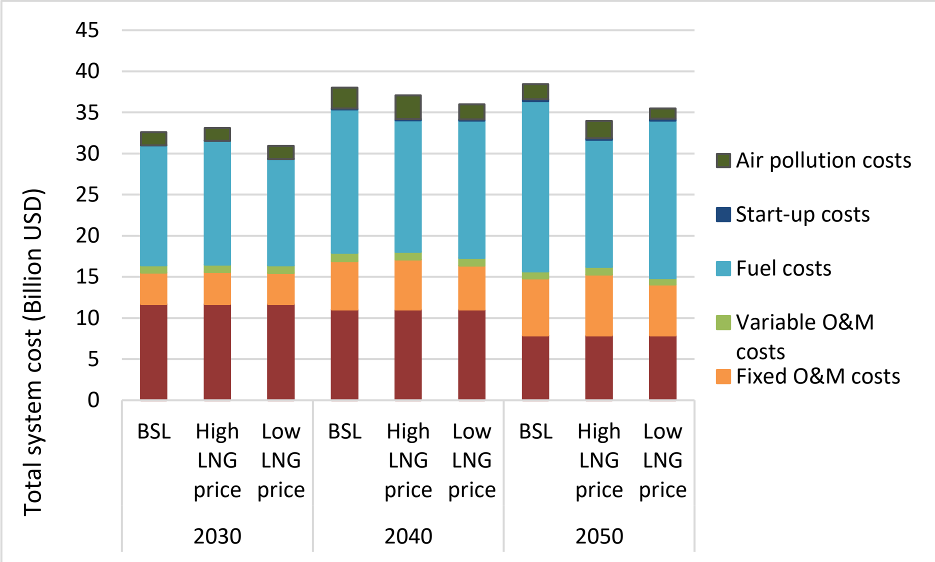


Figure 61: Power system cost of sensitivity scenarios about LNG fuel price.

With high LNG price, comparing with BSL scenario, capacity of LNG will reduce while imported coal, solar, wind and battery will increase. In 2050, coal increase 8.5 GW, LNG reduce 19.6 GW, wind offshore and nearshore increase 5 GW, solar increase 45 GW, battery increase 25 GW. The generation energy proportion of RE will be much over target (reach 60% in 2050 while the RE target is 43%). Capacity of inter-regional transmission in High LNG price scenario is higher than BSL scenario about 3 GW. High LNG price scenario has total system cost higher than BSL scenario about 2.6 billion USD in year 2050 (increase 4%).

With low LNG price, in 2050 imported coal reduce so much (12.6 GW), while LNG will increase 25.5 GW to compensate, wind decrease 9 GW, solar PV reduce 26 GW, and battery reduce 12 GW. The generation energy proportion of RE is reached the target. LNG will develop strongly and replace for coal and renewable energy. Total regional transmission capacity will reduce about 4 GW comparing with BSL scenario due to reducing capacity of solar, wind and imported coal in the Center area. Low LNG price scenario have total system cost is lower than BSL scenario about 8.5 billion USD in year 2050 (reduce 12%) because of lower fuel price.

Sensitivity about high cost of battery, low solar potential in NZ scenario

In high cost battery scenario, investment cost of battery in 2050 will increase 150% compare with main scenarios. In low solar potential scenario, only a half of total solar technical potential (in main scenarios) can be implemented. The results of power sector will be changed as follows:

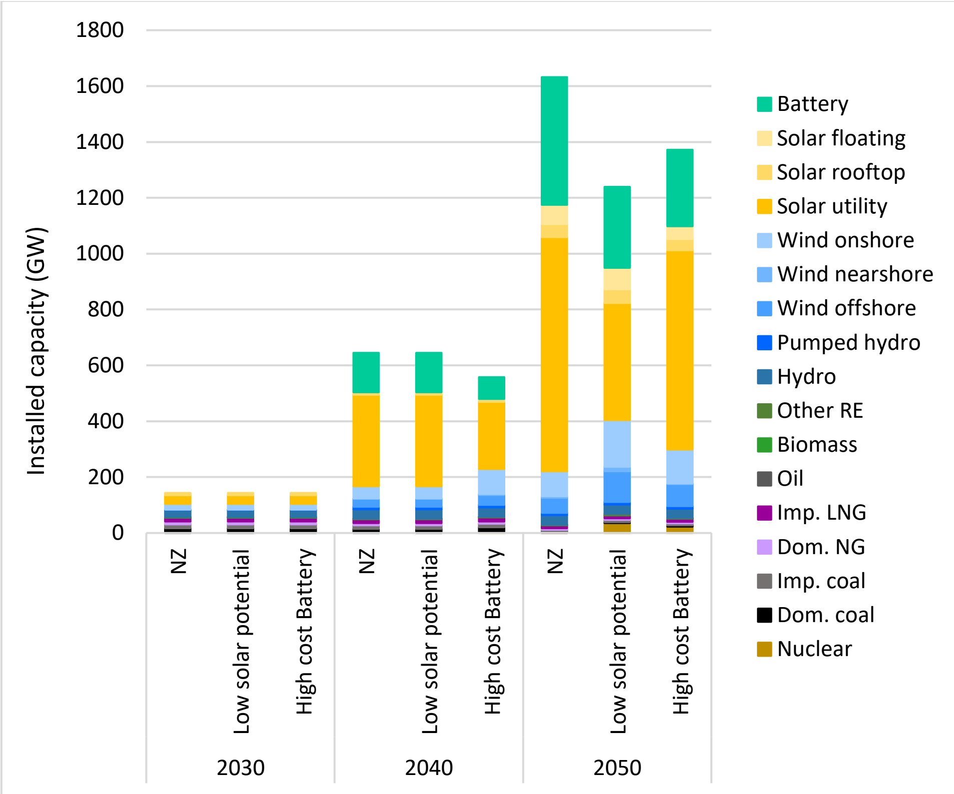


Figure 62: Installed capacity in sensitivity scenarios about low solar potential and high cost battery (exclude import from neighbouring countries)

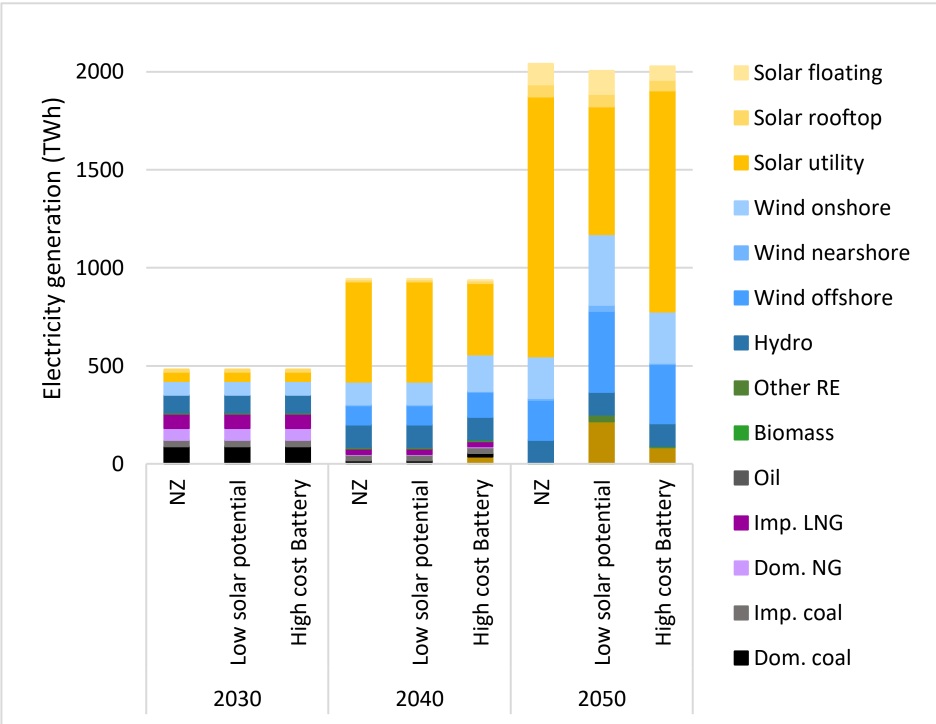


Figure 63: Electricity generation energy in sensitivity scenarios about low solar potential and high cost battery (exclude import from neighbouring countries)

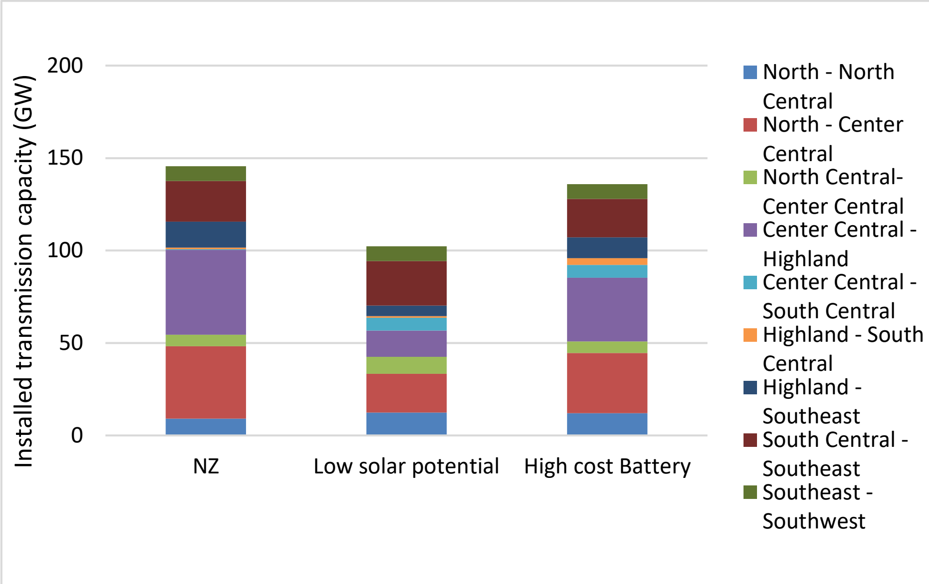


Figure 64: Regional transmission capacity of sensitivity scenarios about low solar potential and high cost battery in 2050.

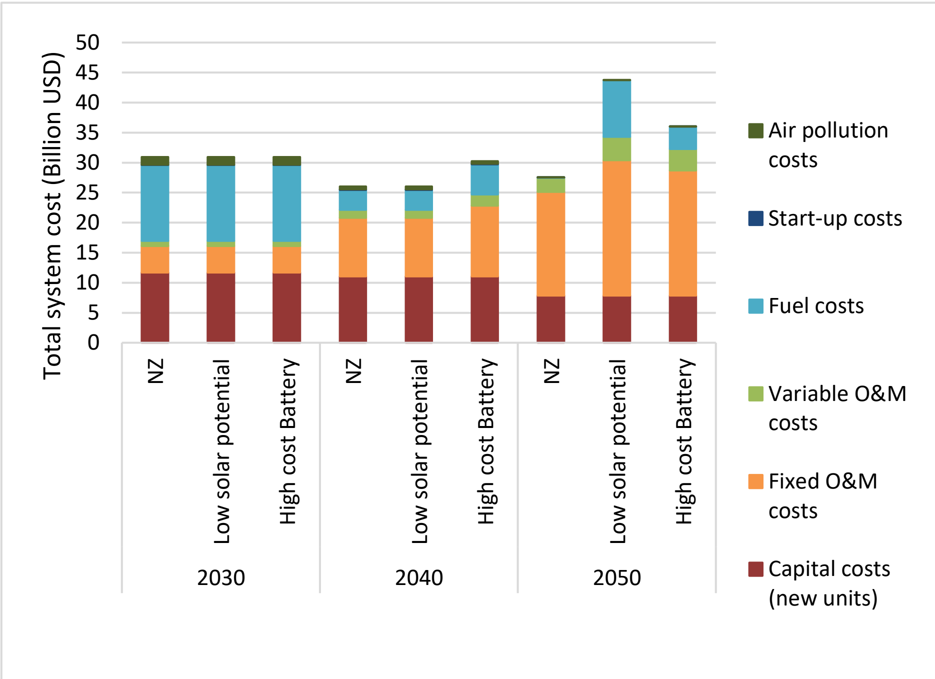


Figure 65: Power system cost of sensitivity scenarios about low solar potential and high cost battery.

With high cost battery, the investment in solar and battery will reduce while investment in nuclear and wind will increase when comparing with NZ scenario. In 2050, nuclear increase 23 GW, offshore wind increases 22 GW, onshore wind increases 31 GW, solar PV reduces 153 GW, battery reduces 183 GW. Capacity of regional transmission reduce 10 GW, total system cost increase 42 billion USD in 2050 (increase about 21%).

With low solar potential, wind and nuclear develop so strongly to compensate for solar and battery. In 2050, nuclear will increase 35 GW, wind (offshore + nearshore + onshore) increases 144 GW, rooftop and floating solar increase 10 GW, while land solar reduces 420 GW and battery reduces 167 GW due to reducing a half of land solar technical potential. Capacity of regional transmission reduce 43 GW, total system cost increase 27 billion USD in 2050 (increase about 13%)

Summary

In sensitivity cases of BSL scenario, solar PV and battery are mainly changed. In BSL scenario, solar PV will develop about 127 GW in 2050, but it can increase more to 80 GW or reduce about 26 GW in sensitivity cases. Battery will be 25 GW in 2050 in BSL scenario, but it can increase more about 43 GW or reduce about 12 GW in sensitivity cases. In 2050, onshore wind can reduce 8 GW with low fuel price, offshore wind can increase 8 GW in low discount rate scenario. LNG can increase 22 GW with low LNG price and reduce 20 GW with high LNG price, coal thermal can increase 10 GW with high demand and reduce 12 GW with low LNG price in 2050.

In sensitivity about high cost battery and low solar potential of NZ scenario, solar and battery will reduce so much, while nuclear and wind will increase for replacement.

7 Discussion and key findings

Electrification of end-use sectors and transport modal shift play a key-role in the green transition

Part of the work leading to this report has been to implement further electrification options in the agriculture and transport sectors. The transport sector has been completely updated compared to the EOR19-report (MOIT and DEA, 2019), so that it now is part of the optimisation procedure. Electrification can add to the reduction of CO_2 emissions in the end-use sectors by increase deployment of variable renewables in the power system. In the GT scenario, electrification of the transport sector increases the total power demand by 10%. An exogenously given modal shift in the transport sector combined with renewable supply for the increased power demand from transport electrification, results in a reduction of 5.9% in the total CO_2 emissions.

Considering health-related pollution costs results in a shift from coal and diesel to LNG

For this study, the health-related costs of air pollutants SO_2, NO_x, and $PM_{2.5}$ have been considered as part of the total system costs but have only been included in the optimisation for one of the scenarios, the AP scenario. For the BSL scenario, the air pollution costs amount to 3.5% of total costs in 2050 corresponding to 13 billion USD19. When including air pollution costs in the optimisation, it shows a reduction in air pollution costs (12 billion USD19 in 2050) and CO_2 emissions, while keeping the total system costs at the same level as the baseline scenario. This indicates that considering air pollution costs when planning can save both lives and costs. These reductions are mainly caused by a shift in the use of coal and diesel towards an increased use of LNG.

Biofuels are a solution in hard-to-abate energy sectors.

The TIMES model has been extended with the option of producing renewable fuels (bio-fuels and e-fuels) from domestic bioresources such as straw and bagasse. The renewable fuels are used in all scenarios and are used to replace mainly gasoline and diesel in the industry, agriculture and transport sectors. The model does not have the option to import biomass and can therefore only produce biofuels from local biomass resources. Further, there is no option for importing biofuels. Import of biomass could add value as there is still a strong need for biofuels in the system. However, importing other country's biomass has other drawbacks, e.g., potential deforestation and reduction in biodiversity.

Wind and solar are essential in the future power system

Due to Vietnam's high-quality resources for wind – both onshore and offshore – and solar PV, the utilization of renewable resources in the power sector is shown to be an excellent way for Viet Nam to supply the growing power demand in a cost-effective way. The BSL scenario overshoots the REDS targets in all years considered, indicating that a least-cost pathway, would require an increase in ambition for the RE share in the power sector – 34% and 51% in 2030 and 2050 respectively. When considering a discount rate of 6.3% instead of 10%, these optimal RE shares increase even more to 54% and 72%, respectively.

Integrating renewables requires transmission build-out and storages

To integrate these large shares of renewable, increased flexibility in the system is required. This flexibility was shown in this study by increased transmission build-out large amounts of batteries (25 - 457 GW in 2050 in the Main scenarios) and . In all scenarios, the interregional build-out of transmission lines was seen to be essential: in 2050, total interregional transmission capacity will be 46 GW in BSL scenario, 72 GW in GP scenario, 46 GW in AP scenario, 49 GW in GT scenario and 150 GW in NZ scenario, while total interregional transmission capacity is 25 GW in 2020. Connecting demand centres such as Hanoi, with the optimal renewable resources from the Central and the Southern regions of Viet Nam will require extensive expansions on the transmission grid. In 2021-2050, it is required to increase the transmissions lines with more than 4 GW of Center Central – North in BSL scenario and AP scenario; 12 GW of Center Central – North and 6 GW of South Central – North in GP scenario; 4 GW of Center Central – North and 2 GW of South Central – North in GT scenario; 40 GW of Highland – North and 20 GW of South Central – North in NZ scenario.

Further flexibility measures included in the system, such as demand-side flexibility and P2X (and X2P), could ameliorate the challenges related to integrating variable renewables in the system even further.

Reaching net zero in 2050

A Net-Zero scenario has been implemented in this report. The scenario includes a CO_2-budget complying with a 2 degree/67% confidence level net global CO_2-reduction pathway where the budget is divided per country by 50% population and 50% GDP based on 2014. The results show a peak in 2035 and a reduction down to 65 $MtCO_2$ in 2050. The remainder of 65 $MtCO_2$ has not been abated in the Net-Zero scenario because of limits in the model setup. However, further abatement of these remaining emissions is possible by means of, e.g., additional biofuel or synthetic fuel (P2X) supply, further electrification options, or energy savings.

When considering the amount of electrification necessary for a Net-Zero scenario, the electrification rate of the end use technologies is 470% higher than the baseline scenario in 2050 – resulting in more than a doubling of the electricity demand. Notably the transport sector starts electrifying already in 2025 while agriculture and industry are late movers. For the Net-Zero scenario, there is a stronger reliance on biofuels compared to the other scenarios and the TIMES model utilised the full potential. Complying with the Net-Zero pathway, yields a substantial reduction of air pollution costs by more than 10 billion USD19 in 2050.

The power sector has seen full decarbonisation in the Net-Zero scenario despite the large demand. This was achieved by exploiting most of the variable renewable energy potential, especially PV. However, also in the power sector, modelling further decarbonisation options could role in the decarbonisation story. A further exploration of the contributions of technologies such as carbon capture, utilization and storage (CCUS), direct air capture, and P2X, could enable the Vietnamese power sector to decarbonize in a more cost-effective way than currently modelled.

References

Battery University (2017). *Compare battery energy with fossil fuel and other resources.* https://batteryuniversity.com/learn/article/bu_1006_cost_of_mobile_power. Accessed 24th of March 2022

C2Wind (2020). *Vietnam Offshore Wind Country Screening and Site Selection*

Central Economics Committee (2020). *National Energy Development Strategy (Resolution no. 55-NQ/TW).*

Coleman, B. (2021), *Assessment of a social discount rate and financial hurdle rates for energy system modelling in Viet Nam*, OECD Environment Working Papers, No. 181, OECD Publishing, Paris, https://doi.org/10.1787/a4f9aff3-en

Danish Energy Agency. (2018). *Balmorel Lite*. http://www.balmorellite.dk/

DSI (2021). *Research and forecasting the Viet Nam economic development scenarios*. Vietnam institute for development strategies (DSI)

Ea Energy Analyses. (2022). *Balmorel model*. https://www.ea-energianalyse.dk/en/themes/balmorel/

Ea and EML (2020). *Model-linking of TIMES and Balmorel*. Ea Energy analysis (Ea) and Energy Modelling Lab (EML)

EML, Ea, and AU (2021). *Viet Nam Energy Outlook 2021 Preparation, Task 1 and 2, Final Report.* Energy Modelling Lab (EML), Ea Energy analysis (Ea), and Aarhus University (AU).

EREA and DEA (2021a). *Fuel Price Projections for Vietnam. Background to the Vietnam Energy Outlook Report 2021.*

EREA and DEA (2021b). *Vietnamese technology catalogue.* Hanoi: Electricity and Renewable Energy Authority & Danish Energy Agency.

IE (2017). *Energy Statistic Yearbook 2015*. Hanoi: Institute of Energy.

IE (2021). *Energy Master plan (draft)*, Social and economic indicators data. Hanoi: Institute of Energy.

IEA (2020). *World Energy Outlook 2020*. IEA, Paris, https://www.iea.org/reports/world-energy-outlook-2020

IRENA (2016). *End-of-life management: Solar PV panels*. ISBN: ISBN 978-92-95111-99-8, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2016/IRENA_IEAPVPS_End-of-Life_Solar_PV_Panels_2016.pdf

MOIT and DEA. (2017). *Viet Nam Energy Outlook Report 2017.* Danish Energy Agency (DEA) and the Vietnamese Ministry of Industry and Trade (MOIT).

MOIT and DEA. (2019). *Viet Nam Energy Outlook Report 2019.* Danish Energy Agency (DEA) and the Vietnamese Ministry of Industry and Trade (MOIT).

MPI (2021). *National Green Growth Strategy for 2021-2030, vision towards 2050*. Ministry of Planning and Investment (MPI)

NLDC (2021). *Annual power system operation report.* National Load Dispatch Center (NLDC)

VNEEP (2021). *Vietnam Energy Statistic, 2020*. National energy efficiency Program (VNEEP)

Annex: Methodology of assessment of costs related to human health impacts from air pollution

The methodology behind the inclusion of health-related costs from air pollution can be divided into three steps. The purpose of the two first steps is to provide assessments of the cost of emitting a unit of NO_X, SO_2, and $PM_{2.5}$, also called 'unit costs' for today whereas, in the third step, these unit costs are applied in the energy system modeling and optimization setup. Figure 66 shows an overview of the methodology.

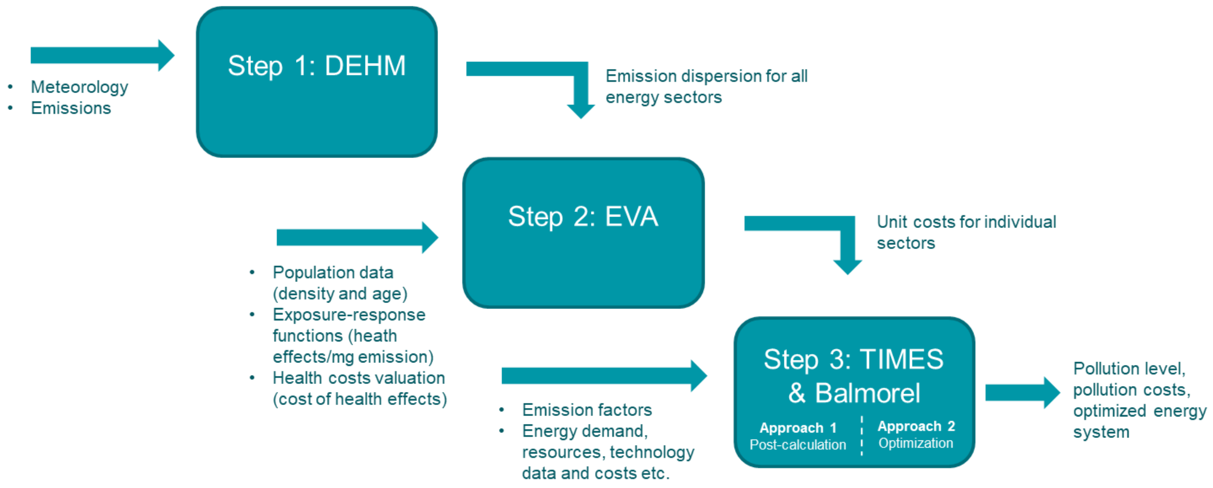


Figure 66: Overview of methodology

In the first step, the dispersion of pollutants is assessed in a meteorological model based on historical emissions, weather patterns, and chemical reactions in the atmosphere.

In the second step, the concentration of pollutants is combined with population data (density and age) to determine the exposure of pollutants to humans. By using exposure-response functions, it is possible to estimate the health effects, which are then valuated to determine the unit costs.

In the third step, the unit costs are linked to emissions of the air pollutants in the energy system modeling setup of TIMES and Balmorel.

Step 1: Dispersion and concentration of emissions

The first step tracks the long-range dispersion of pollutants on a sectoral level based on historical emissions, weather patterns, and chemical reactions in the atmosphere. This is done by the Danish Eulerian Hemispheric Model (DEHM)[i], a model originally developed for air quality monitoring in Denmark and Europe. The model has been thoroughly validated and reviewed in various scientific journals.

The DEHM is an atmospheric 3D model nested in different domains down to 17x17 km resolution with a detailed meteorological and surface representation. The DEHM includes seven different chemical compounds from six different sectors as seen in Table 17 below, although only three chemical compounds are used for the energy system modeling in Step 3. The geographical distribution is displayed in Figure 67.

HTAP_v2 emission data for Viet Nam for 2010 (ktonnes). Given as kg-S, kg-C, kg-N, kg-NMVOC, kg-PPM$_{2.5}$						
Emission sector	SO_2	CO	NO_x	NMVOC	NH_3	$PM_{2.5}$
SNAP01 - Energy production and transformation	53	4	26	2	0	6
SNAP02 - Residential	40	2552	26	1083	160	2
SNAP03 - Industry	132	43	34	153	5	135
SNAP07 - Road/land transport	36	714	41	835	1	2
SNAP08 - Aviation	0	1	2	0		0
SNAP10 - Agriculture					346	
Ship transport, EEZ Vietnam	133	21	160	16		
Total	395	3335	289	2089	512	145

Table 17: Historical emissions aggregated for all of Viet Nam in 2010 from the HTAP_v2 database is used as input to the DEHM. Emissions are given as kg-S, kg-C, and kg-N. To convert e.g. S to SO2 based on the molecular mass a conversion factor of 2.00 has to be used, and hence the total emission of SO_2 is 2x395=790 ktonnes in SO_2 units, and similar factors of 2.33 for CO, 3.29 for NO_X (kton-NO2), and 1.21 for NH_3.

Emission data

The data of historical emission of pollutants is from the HTAP_v2 database from 2010. This database has the highest quality of data for Asia and Vietnam, considering emissions levels and spatial distribution of emissions. Further, the database has been applied and evaluated in a model inter-comparison study for Asia (MICS-Asia). As the DEHM model is not used to determine present or future emission levels, but rather to model the dispersion pattern (geographical location of emission, etc.) of emissions due to specific meteorology, it is reasonable to use data from 2010, although Viet Nam has undergone rapid development in the last decade. It would strengthen the analysis further to apply more updated data, potentially from a national high-quality and high-resolution emission inventory, and it is recommended to support such development.

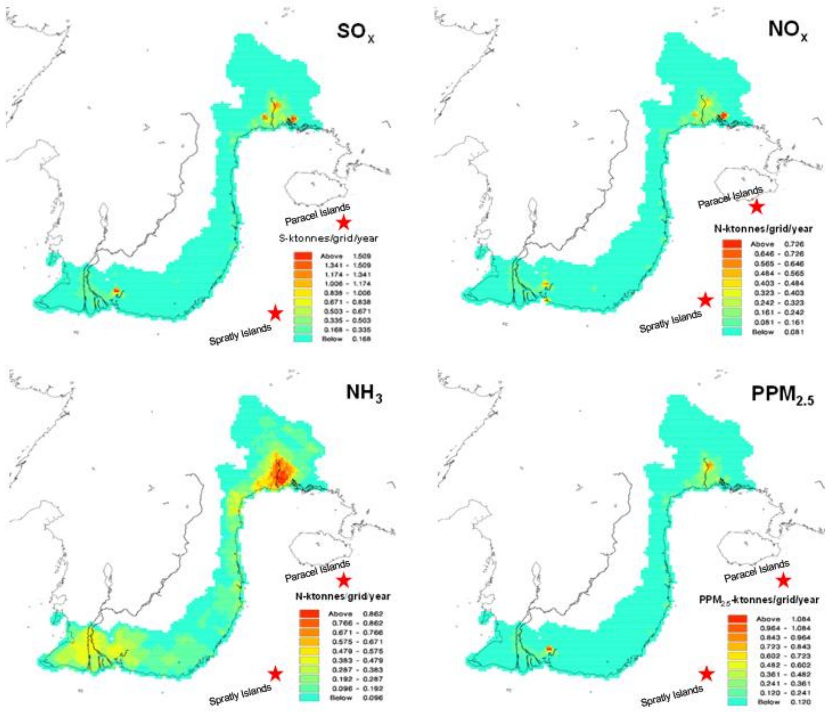


Figure 67: Geographical distribution of emissions of SO_x, NO_x, NH_3, and $PM_{2.5}$ in Viet Nam in 2010 from the HTAP_v2 database aggregated for all sectors.

Meteorological data

Meteorological data is from 2019 and calculated using the meteorological model (WRF - Weather Research and Forecasting model) and setup on the same domains as DEHM.

DEHM results

Figure 68 below displays the resulting mean annual concentration of $PM_{2.5}$, NO_2, O_3, and SO_2 using HTAP_v2 data and metrology data from 2019.

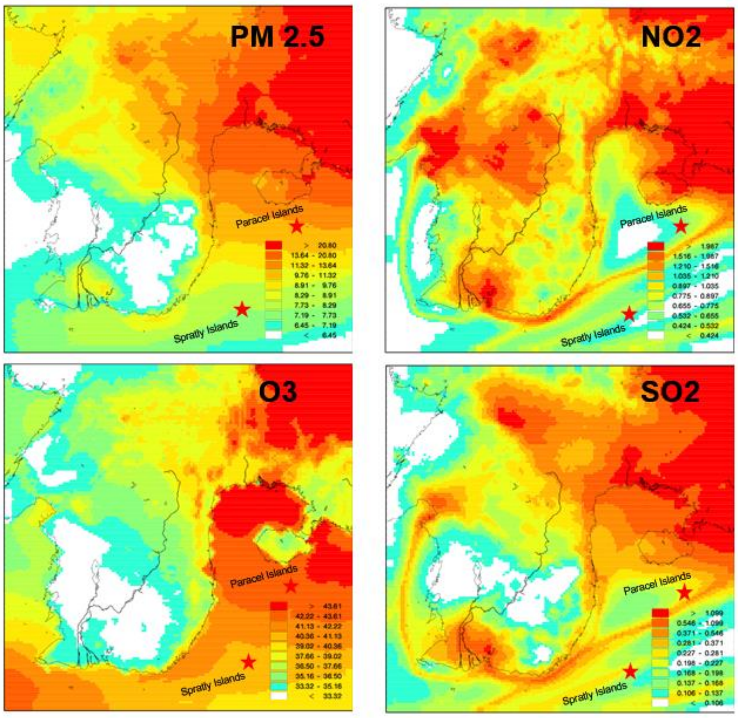


Figure 68: Geographical distribution of annual mean concentrations (µg/m3) of SO_x, NO_x, NH_3, and $PM_{2.5}$ from DEHM modeling.

Step 2: Human exposure, health effects, health costs, and unit costs

The second step combines the concentration of pollutants from DEHM with population data (density and age) to determine the exposure of pollutants to humans. By using exposure-response functions, it is possible to estimate the health effects. When health effects are valuated, it is possible to determine the unit costs.

Table 18 shows the valuation of health effects in Vietnam. These are determined by transferring health valuation from Denmark to Viet Nam by using the OECD benefit transfer methodology:

$VSL_{VN} = VSL_{DK} (Y_{VN}/Y_{DK})^{ß}$

where VSL is the value of statistical life, Y is the GDP per capita (PPP adjusted) and ß reflects an income elasticity of 0.8.

Health endpoint	Pollutant	Range	Ages	RR per 10 µg/m3	Costs in Vietnam	
Acute mortality	O_3	>35 ppb	All	1.0029	493,840	USD/case
	NO_2 (daily max)	no thresh.	All	1.0027		
	$PM_{2.5}$	no thresh.	All	1.0123		
	SO_2	no thresh.	All	0.072		
Acute mortality infants	$PPM_{2.5}$ (from PPM_{10})	no thresh.	Infants	1.04	740,585	USD/case
Chronic mortality	$PM_{2.5}$	no thresh.	>30	1.062	17,413	USD/YOLL
	NO_2	>20 ug/m3	>30	1.055		
Hospital admissions (HA):						
Cardiovascular HA/incl. stroke	$PM_{2.5}$	no thresh.	All	1.0091	1,862	USD/case
Cardiovascular HA/excl. stroke	O_3	>35 ppb	>65	1.0089	1,848	USD/case
Respiratory HA	$PM_{2.5}$	no thresh.	All	1.019	1,157	USD/case
Respiratory HA	O_3	>35 ppb	>65	1.0044		
Respiratory HA	NO_2	no thresh.	All	1.018		
Bronchitis (KOL)/children	$PM_{2.5}$ (from PM_{10})	no thresh.	6-18	1.048	19	USDs/case
Bronchitis (KOL)/adults	$PM_{2.5}$ (from PM_{10})	no thresh.	>18	1.117	4,532	USDs/case
Asthma symptoms/children	$PM_{2.5}$ (from PM_{10})	no thresh.	5-19	1.028	154	USDs/day
Days with restricted activity (sick days) ($PM_{2.5}$)	$PM_{2.5}$	no thresh.	All	1.047	17	USDs/day
Working days lost ($PM_{2.5}$)	$PM_{2.5}$	no thresh.	20-65	1.046	32	USDs/day
Days with minor restricted activity (O_3)	O_3	>35 ppb	All	1.0154	9	USDs/day
Lung cancer morbidity	$PM_{2.5}$	no thresh.	>30	1.14	8,462	USDs/case

Table 18: The health endpoints and relative risks used in EVA – based on the WHO recommendations (the RR for SO_2 is taken from the ExternE project).

The unit costs for each sector and pollutant in 2016 are displayed in Table 19. Future unit costs are scaled by population as in PDP8[4] and EMP as displayed in Figure 69.

Species emissions	SO_x	NO_x	NH_x	NMVOC	$PPM_{2.5}$
Species Impacts	**SO_2+SO_4**	**O_3-O_3neg +NO_3+NO_2**	**NH_4**	**SOA**	**$PM_{2.5}$**
SNAP01 – Energy production and transformation	2	4	-	-	5
SNAP02 – Residential	6	11	2	1	31
SNAP03 – Industry	2	5	-	0	6
SNAP07 – Road/land transport	3	6	-	0	17
SNAP08 – Aviation	-	-	-	-	-
SNAP10 – Agriculture	0	0	1	0	0
SNAP15 – Ship transport	2	2	0	8	3

Table 19: The unit costs for each sector and pollutant in 2016 (USD19/kg).

The unit costs vary between sectors since some sectors have a larger exposure to the population than others. As an example, one kg of $PM_{2.5}$ emitted in the residential sector e.g., from a wood-fired cooking stove has a larger impact on people in and around this household than one kg of $PM_{2.5}$ emitted from a coal-

[4] The applied health unit cost of air pollution in PDP8 is approximately 7 USD/kg for $PM_{2.5}$ and 5 USD/kg for NO_x and SO_2 in 2020, which increases towards 2030 and 2045 with the same rate of expected population growth.

fired power plant (energy production and transformation sector) with fewer people in near proximity.

Figure 69: Pollution costs used in the energy system models for the different sectors. AGR denotes agriculture, COM commercial, IND industry, PWR power, RSD residential, TRA-AIR air transport, TRA-ROAD road transport, and TRA-WATER water transport.

Step 3: Unit costs applied in energy system optimization

In step 3, the unit costs are added to the energy system model. There are two distinct ways of analyzing the health costs of air pollution. In Approach 1, unit costs are added "on top" of other costs after optimization. With this approach, the optimal energy system does not change. In Approach 2, unit costs are internalized in optimization. This drives changes in investment and dispatch profile towards less pollution.

Emission factors

All emitting processes in TIMES and Balmorel need to be specified by an emission factor to associate fuel consumption with the emission level of pollutants. Emission factors from the transport sector are from the online GAINS - South Asia model[ii]. Power sector emissions factors are mainly based on the Vietnamese Technology Catalogue[iii] and the Viet Nam Balmorel model. The remaining sectors rely on emission factors from Denmark[iv]. Within the project scope, it has not been possible to verify the Danish numbers in Viet Nam and it is recommended to further strengthen and develop the data foundation on emission factors in the future.

Emission factors – TIMES

In TIMES, the emission factors shown in Table 20 have been applied for the power sector. These emission factors are for most of the technologies the same as for Balmorel. However, due to different spatial and sectoral aggregation levels between the models, some emission factors were subject to change to account for these structural differences. Some of the technologies were not given in the data for Balmorel – here Danish numbers have been applied. For a few of the technologies, the emission for the fuel given in Balmorel was found to be much lower than the Danish numbers – here a scaling factor has been used to find an equivalent number for a Vietnamese technology.

Input	NO_x	SO_2	$PM_{2.5}$	Technology	Source
Coal	152	39.06	8.2		B
Fuel oil	108.4	408	3.56		B
Diesel	108.4	212.4	3.56		B
Natural gas	68	0.43	0.1		NO_x: B, $SO_2/PM_{2.5}$: D
Natural gas	328	0.5	0.16	Engine	NO_x: M, $SO_2/PM_{2.5}$: D
Natural gas	117	0.43	0.051	Existing turbine	NO_x: M, $SO_2/PM_{2.5}$: D
Municipal waste	75	8.3	0.29		D
Primary solid bio-fuels	125	1.9	1.8	Steam turbine	B
Primary solid bio-fuels	221	8.9	2	Integrated gasification combined cycle	B
Biogas	28	25	1.5		D
Biogas & landfill gas	202	19.2	0.206	Engine	D
Bagasse	125	1.9	1.8		B

Table 20: Emission factors for the power production in TIMES [g/GJ]. A "B" denotes that data is from Bal-morel, a "D" that it is from Danish numbers, and "M" that a multiplication factor has been used to convert a Danish number to a Vietnamese technology.

For coal and natural gas, a development in the emission factor of NO_x is given from Balmorel (p. 110). The future development in emission factors for the relevant technologies is shown in Table 21. A coal technology installed in 2030 would thereby have a lower NO_x emission than a coal technology installed in 2010. The years in between the years given in the table will have a linear decrease in emission factor.

Input	2010	2020	2030	2040	2050
Coal	152	152	150	150	50
Natural gas	68	68	50	50	30
Natural gas - engine	328	328	241	241	117

Table 21: Development in the emission factor of NO_x for technologies in the power sector in TIMES using coal or natural gas as input [g/GJ].

For the agricultural, commercial, and residential sector, all emission factors are given by fuel only. The emission factors applied in each sector are given in Table 22.

Sector	Input	NO_x	SO_2	$PM_{2.5}$
Agricultural	Coal	95	397	7
	Fuel oil	142	344	7
	Diesel and gasoline	52	6.7	5
Commercial	Coal	95	397	7
	Kerosene	51	5	5
	Diesel	52	6.7	5
	LPG	71	0.13	0.2
Residential	Coal	95	397	7
	Kerosene	52	6.7	5
	Diesel	51	5	5
	LPG	47	0.13	0.2
	Primary solid biofuels	73	11	290
	Rice husk, straw, bagasse, other biomass	154	115	433
	Biogas	19.6	25	0.1

Table 22: Emission factors for agriculture, commercial and residential sectors [g/GJ].

For the industrial sector, the emission factors have been applied mainly on a pr. fuel level. However, for the generation of process heat for the cement and iron & steel sector, a different emission factor has been applied to the use of coal, natural gas, and fuel oil. The applied factors are shown in Table 23. All the emission factors are Danish numbers.

Input	NO_x	SO_2	$PM_{2.5}$
Coal	183	359	7
Coal – Process heat	189	232	7
Natural gas	61.2	0.45	0.1
Natural gas – Process heat	61.6	0.45	0.1
Fuel oil	129	344	4.8
Fuel oil – Process heat	161.9	344	4.8
Diesel	130	6.7	5
Kerosene	51	5	5
LPG	96	0.13	0.2
Primary solid biofuels, rice husk, and other biomasses	90	11	10

Table 23: Emission factors for the industrial sector [g/GJ].

Emission factors from the transport sector factors are from the online GAINS - South Asia model, see Table 24.

Pollutant TIMES Technology Type	NOx Existing	 Emis1	 Emis2	PM2.5 Existing	 Emis1	 Emis2	SO2 Existing	 Emis1	 Emis2
Car: Gasoline - Compact- Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Car: Gasoline - Fullsize- Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Car: Gasoline - Large SUV- Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Car: Gasoline - MiniCompact- Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Car: Gasoline - Minivan- Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Car: Gasoline - Pickup- Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Car: Diesel - Compact- Conventional	402.5	385	350	23.2	22.62	1.19	20.74	10.6	0.46
Car: Diesel - Fullsize- Conventional	402.5	385	350	23.2	22.62	1.19	20.74	10.6	0.46
Car: Diesel - Large SUV- Conventional	402.5	385	350	23.2	22.62	1.19	20.74	10.6	0.46
Car: Diesel - Minivan- Conventional	402.5	385	350	23.2	22.62	1.19	20.74	10.6	0.46
Car: Diesel - Pickup- Conventional	402.5	385	350	23.2	22.62	1.19	20.74	10.6	0.46
Car: Diesel - Small SUV- Conventional	402.5	385	350	23.2	22.62	1.19	20.74	10.6	0.46
Scooter and Motorbike: Gasoline - Scooter&Motorbike-Conventional	200	200	148	120.9	74.4	29.76	0.45	0.45	0.45
Scooter and Motorbike: Diesel - Scooter&Motorbike- Conventional	200	200	148	120.9	74.4	29.76	20.74	10.6	0.46
Heavy Commercial Vehicle - Bus: Kerosene - Conventional	154.8	86	60.2	13.18	4.31	4.07	0.45	0.45	0.45
Heavy Commercial Vehicle - Bus: LPG - Conventional	154.8	86	60.2	1.01	0.33	0.31	0.45	0.45	0.45
Heavy Commercial Vehicle - Bus: Fuel Oil - Conventional	1300	1300	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Bus: Diesel and biodiesel blend- Conventional	1300	1300	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Bus: Diesel - Conventional	1300	1300	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Bus: Natural Gas - Conventional	117	65	45.5	1.01	0.33	0.31	0.45	0.45	0.45
Heavy Commercial Vehicle - Coach: Kerosene - Conventional	154.8	86	60.2	13.18	4.31	4.07	0.45	0.45	0.45
Heavy Commercial Vehicle - Coach: LPG - Conventional	154.8	86	60.2	1.01	0.33	0.31	0.45	0.45	0.45
Heavy Commercial Vehicle - Coach: Fuel Oil - Conventional	1300	1300	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Coach: Diesel and biodiesel blend- Conventional	1300	1300	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Truck: Diesel - Long haul- Conventional	1170	845	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Truck: Diesel - Long haul- Conventional	1170	845	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Truck: Diesel - Short haul- Conventional	1170	845	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Truck: Diesel - Medium haul-Conventional	1170	845	390	26.65	7.13	7.17	20.74	10.6	0.46
Heavy Commercial Vehicle - Truck: Gasoline and Biogasoline blend- Conventional	154.8	86	60.2	13.18	4.31	4.07	0.45	0.45	0.45
Heavy Commercial Vehicle - Truck: Diesel and biodiesel blend- Conventional	1170	845	390	26.65	7.13	7.17	20.74	10.6	0.46
Light Commercial Vehicle - Passenger: LPG - Conventional	68.8	34.4	25.8	0.33	0.33	0.31	0.45	0.45	0.45
Light Commercial Vehicle - Passenger: Kerosene - Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Light Commercial Vehicle - Passenger: Gasoline - Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Light Commercial Vehicle - Passenger: Aviation Gasoline - Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Light Commercial Vehicle - Passenger: Diesel - Conventional	402.5	385	350	19.95	19.45	1.03	20.74	10.6	0.46
Light Commercial Vehicle - Goods: LPG - Conventional	402.5	385	350	0.33	0.33	0.31	0.45	0.45	0.45

Light Commercial Vehicle - Goods: Diesel - Pickup- Conventional	402.5	385	350	19.95	19.45	1.03	20.74	10.6	0.46
Light Commercial Vehicle - Goods: Gasoline - Minivan- Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Light Commercial Vehicle - Goods: Aviation Gasoline - Conventional	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Light Commercial Vehicle - Goods: Diesel - Minivan- Conventional	402.5	385	350	19.95	19.45	1.03	20.74	10.6	0.46
High-speed Passenger Rail: Kerosene - Conventional	68.8	34.4	25.8	5.04	5.04	4.76	0.45	0.45	0.45
High-speed Passenger Rail: Aviation Gasoline - Conventional	68.8	34.4	25.8	5.04	5.04	4.76	0.45	0.45	0.45
High-speed Passenger Rail: Diesel and biodiesel blend- Conventional	522	348	220.4	14.46	2.89	5.79	20.74	10.6	0.46
Mainline & Suburban Passenger: Diesel	522	348	220.4	14.46	2.89	5.79	20.74	10.6	0.46
Metro: Kerosene - Commuter	68.8	34.4	25.8	5.04	5.04	4.76	0.45	0.45	0.45
Metro: Kerosene - Intercity	68.8	34.4	25.8	5.04	5.04	4.76	0.45	0.45	0.45
Mainline Goods Rail: Diesel - Intercity	522	348	220.4	14.46	2.89	5.79	20.74	10.6	0.46
Coastal Freight: Fuel Oil	522	348	220.4	15.75	3.15	6.3	20.74	10.6	0.46
Inland Waterway Freight: Diesel	522	348	220.4	15.75	3.15	6.3	20.74	10.6	0.46
Inland waterway and Coastal Passenger: Diesel	522	348	220.4	15.75	3.15	6.3	20.74	10.6	0.46
Non registered motorized craft passenger: Diesel	1170	845	390	26.65	7.13	7.17	20.74	10.6	0.46
Non registered motorized craft freight: Diesel	1170	845	390	26.65	7.13	7.17	20.74	10.6	0.46
Off-road : LPG	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45
Off-road : Kerosene	68.8	34.4	25.8	6.51	6.51	6.15	0.45	0.45	0.45

Table 24: Emission factors for the transport sector [g/GJ].

Emission factors - Balmorel

Balmorel uses emission factors for CO_2 and SO_2 as shown in Table 25. These are based on international numbers and confirmed for use in the Vietnamese context by the Institute of Energy.

	CO_2 (kg/GJ)	SO_2 (kg/GJ)
Coal	95.0	0.714
Natural gas	56.8-73.8*	-
Fuel oil	78.0	1.000
Diesel	74.0	0.561
Biomass	-	0.025
MSW	-	0.156

*Table 25: Emission factors for CO_2 and SO_2 in the power sector [g/GJ]. * CO_2 emissions for natural gas depend on the origin (CVX: 73.8, Block B: 62.5, other domestic NG and LNG: 56.8)*

Emission factors for NO_x and $PM_{2.5}$ as well as desulfurization percentage are directly assigned to each generation technology in the Balmorel model. The full overview can be found in Table 26. For existing and committed technologies, the data is based on technology data received from the Institute of Energy. For investment technologies, data is based on the Vietnamese Technology Catalogue.

Existing	Desulfurization SOx %	NO_x g/GJ	PM g/GJ
Na Duong I #1	95%	29.54	8.04
Na Duong I #2	95%	29.54	8.04
Pha Lai 1	26%	303.59	8.26
Pha Lai 2	93%	303.59	8.26
Uong Bi	93%	303.59	8.26
Uong Bi Extension 1	93%	303.59	8.26
Uong Bi Extension 2	93%	303.59	8.26
C.Ngan 1	95%	29.54	8.04
C.Ngan 2	95%	29.54	8.04
North Diesel	0%	149.70	89.47
Hai Phong I#1	93%	303.59	8.26
Hai Phong I#2	93%	303.59	8.26
Hai Phong II #1	93%	303.59	8.26
Hai Phong II #2	93%	303.59	8.26
NĐ Cam Pha I	95%	28.72	7.82
NĐ Cam Pha II	95%	28.72	7.82
Quang Ninh I #1	93%	295.38	8.04
Quang Ninh I #2	93%	295.38	8.04
Quang Ninh II #1	93%	295.38	8.04
Quang Ninh II #2	93%	295.38	8.04
Son Dong #1	95%	29.54	8.04
Son Dong #2	95%	29.54	8.04
Mao Khe I-220MW	95%	29.54	8.04
Mao Khe II-220MW	95%	29.54	8.04
Mong Duong I #1	28%	295.38	8.04
Mong Duong I #2	28%	295.38	8.04
Mong Duong II #1	93%	295.38	8.04
Mong Duong II #2	93%	295.38	8.04
Thai Binh I #1	93%	303.59	8.26
An Khanh #1	95%	29.54	8.04
An Khanh #2	95%	29.54	8.04
Nghi Son #1	93%	303.59	8.26
Nghi Son #2	93%	303.59	8.26
Vung Ang I #1	93%	295.38	8.04
Vung Ang I #2	93%	295.38	8.04
Formusa HT1 (cogen)	93%	303.59	8.26
ND Than Nong Son	93%	303.59	8.26
Loc dau Dung Quat	16%	125.88	75.23
Phu My 2-1		-	-
Phu My 2-1 extension		-	-

Phu My 2.2		-	-
Dam Phu My		-	-
Nhon Trach I CC		59.22	-
Nhon Trach II CC		59.22	-
Thu Duc #1 ST	45%	81.65	48.80
Thu Duc #2 ST	45%	81.65	48.80
Thu Duc #3 ST	45%	81.65	48.80
Thu Duc #4 GT	45%	81.65	48.80
Thu Duc #5 GT	45%	81.65	48.80
Thu Duc #6 GT	45%	81.65	48.80
Thu Duc #7 GT	45%	81.65	48.80
Thu Duc #8 GT	45%	81.65	48.80
Ba Ria GT #1	100%	28.24	-
Ba Ria GT #2	100%	28.24	-
ND Can Tho	69%	81.65	48.80
TBK Can Tho	0%	149.70	89.47
O Mon I #1-FO		132.69	79.30
O Mon I #2-FO		-	-
Ca Mau I CC		47.38	-
Ca Mau II CC		47.38	-
Hiep Phuoc (IPP) #1 ST		149.70	89.47
Hiep Phuoc (IPP) #2 ST		149.70	89.47
Hiep Phuoc (IPP) #3 ST		149.70	89.47
Amata+Vedan		361.02	9.83
ND than Vedan	93%	303.59	8.26
Formosa 1	93%	30.36	8.26
Formosa 2	93%	30.36	8.26
Formosa 3	93%	30.36	8.26
Vinh Tan II #1	93%	30.36	8.26
Vinh Tan II #2	93%	30.36	8.26
Vinh Tan I #1	93%	30.36	8.26
Duyen Hai I #1	93%	30.36	8.26
Duyen Hai I #2	93%	30.36	8.26
Duyen Hai III #1	93%	30.36	8.26
Duyen Hai III #2	93%	30.36	8.26
Duyen Hai III #3	93%	30.36	8.26
Vinh Tan IV#1	91%	35.28	9.60
Vinh Tan IV#2	91%	35.28	9.60
Phu My 4		-	-
Phu My 1		-	-
Phu My 3		-	-
BaRiaC/C#1GT3x37.5ST56		47.38	-
Ba Ria C/C#2 GT3x37.5MW, ST1x62M		47.38	-

Committed			
Na Duong II	86%	152	18.9
Thang Long I	86%	152	18.9
Thai Binh I #2	86%	152	18.9
Thai Binh II #1	86%	152	18.9
Thai Binh II #2	86%	152	18.9
Hai Duong #1	86%	152	18.9
Hai Duong #2	86%	152	18.9
Nam Dinh I #1	86%	152	18.9
Nam Dinh I #2	86%	152	18.9
ND Hai Ha 1 (cogen)	86%	152	18.9
An Khanh II	86%	152	18.9
Nghi Son II #1	86%	152	18.9
Nghi Son II #2	86%	152	18.9
Vung Ang II #1	86%	152	18.9
Quang Trach I #1	86%	152	18.9
Quang Trach I #2	86%	152	18.9
Formusa HT2 (cogenaration)	86%	152	18.9
Cong Thanh	86%	152	18.9
TBKHH Dung Quat #1		78	7.2
TBKHH Mien Trung 1		78	7.2
Nhon Trach III CC		78	7.2
Nhon Trach IV CC		78	7.2
O Mon III - Lo B		78	7.2
O Mon IV - Lo B		78	7.2
Vinh Tan I #2	86%	152	18.9
Vinh Tan III #1	86%	152	18.9
Duyen Hai II #1	86%	152	18.9
Duyen Hai II #2	86%	152	18.9
Long Phu I #1	86%	152	18.9
Long Phu I #2	86%	152	18.9
Song Hau I #1	86%	152	18.9
Song Hau I #2	86%	152	18.9
Vinh Tan IV ext	86%	152	18.9
TBKHH Dung Quat #2		78	7.2
TBKHH Mien Trung 2		78	7.2
Investment - Balmorel name			
Coal_High_Sub_20_29	86%	152	18.9
Coal_Low_Sub_20_29	86%	152	18.9
Coal_Imp_Sub_20_29	86%	152	18.9
Coal_High_Sub_30_49	86%	150	18.9
Coal_Low_Sub_30_49	86%	150	18.9
Coal_Imp_Sub_30_49	86%	150	18.9

Coal_High_Sub_50	95%	38	18.9
Coal_Low_Sub_50	95%	38	18.9
Coal_Imp_Sub_50	95%	38	18.9
Coal_High_Super_20_29	86%	152	18.9
Coal_Imp_Super_20_29	86%	152	18.9
Coal_High_Super_30_49	86%	150	18.9
Coal_Imp_Super_30_49	86%	150	18.9
Coal_High_Super_50	95%	38	18.9
Coal_Imp_Super_50	95%	38	18.9
Coal_High_Ultra_Super_30_49	86%	150	18.9
Coal_Imp_Ultra_Super_30_49	86%	150	18.9
Coal_High_Ultra_Super_50	95%	38	18.9
Coal_Imp_Ultra_Super_50	95%	38	18.9
Coal_AUSC_35_50	95%	38	18.9
Coal_CCS_High_30_49	86%	150	18.9
Coal_CCS_Low_30_49	86%	150	18.9
Coal_CCS_Import_30_49	86%	150	18.9
Coal_CCS_High_50	95%	38	18.9
Coal_CCS_Low_50	95%	38	18.9
Coal_CCS_Import_50	95%	38	18.9
CCGT_East_NG_20_29		78	7.2
CCGT_West_NG_20_29		78	7.2
CCGT_CVX_20_29		78	7.2
CCGT_LNG_20_29		78	7.2
CCGT_East_NG_30_49		60	7.2
CCGT_West_NG_30_49		60	7.2
CCGT_CVX_30_49		60	7.2
CCGT_LNG_30_49		60	7.2
CCGT_East_NG_50		20	7.2
CCGT_West_NG_50		20	7.2
CCGT_CVX_50		20	7.2
CCGT_LNG_50		20	7.2

Table 26: Desulfurization, emissions of NO_x and $PM_{2.5}$ per technology in Balmorel.

[i] https://envs.au.dk/en/research-areas/air-pollution emissions-and-effects/the-monitoring-program/air-pollution-models/dehm/technical-description/

[ii] IIASA, 2021: GAINS – South Asia (online model), https://gains.iiasa.ac.at/models/gains_models3.html

[iii] EREA & DEA: Vietnamese Technology Catalogue 2021 (2021).

[iv] https://envs.au.dk/en/research-areas/air-pollution emissions-and-effects/air emissions/emission-factors/