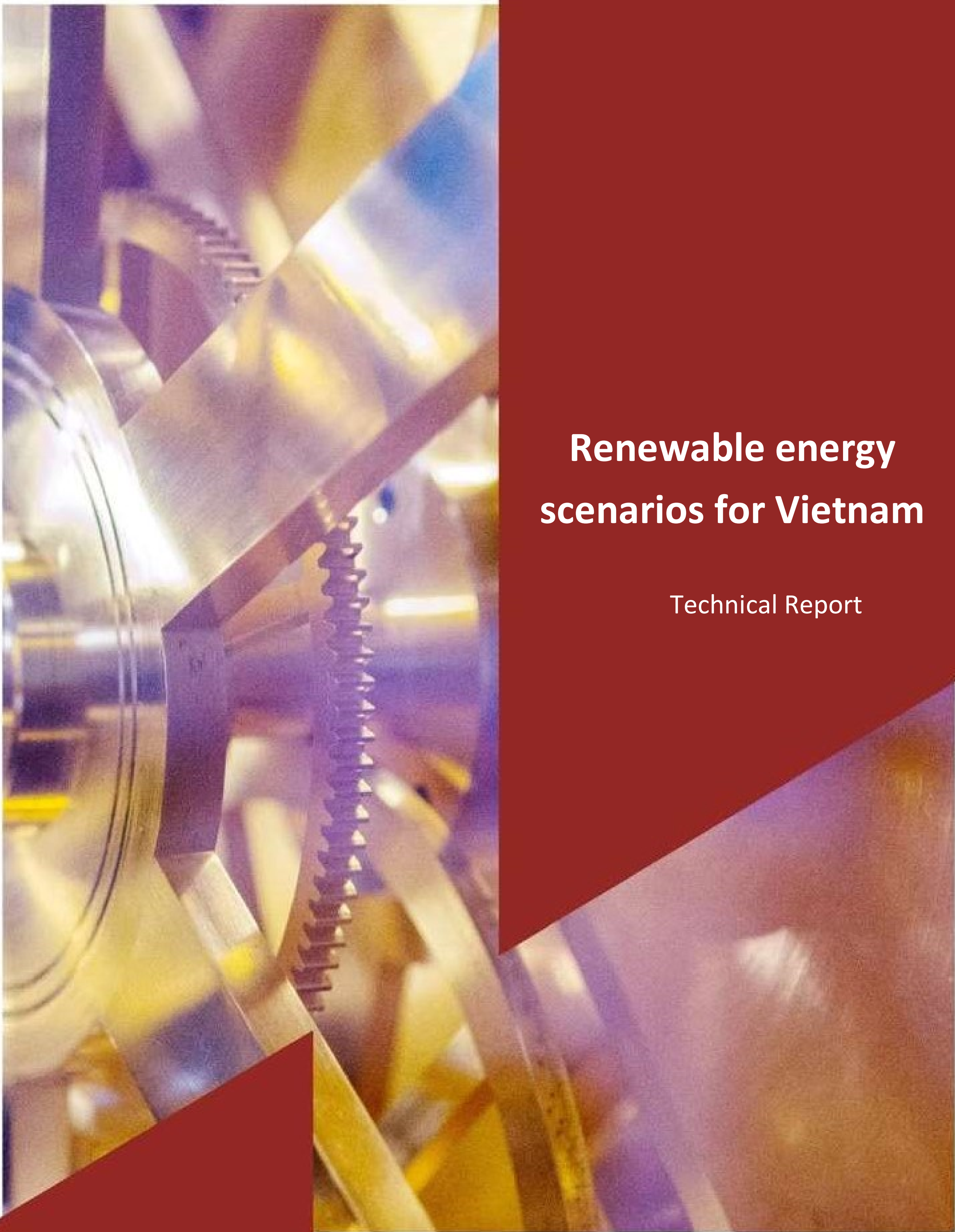

Renewable energy scenarios for Vietnam

Technical Report

Ea Energy Analyses

Danish Energy Agency

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Introduction and background

This is a Technical Report relating to the project ‘Model-Based Power Sector Scenarios for Vietnam’. The project is carried out by Ea Energy Analyses in collaboration with the Institute of Energy (Viện Năng lượng) within the framework of the Danish-Vietnamese cooperation between the Danish Energy Agency, the Danish Embassy in Vietnam and the Ministry of Industry and Trade of Vietnam.

This Technical Report documents the scenarios and results of the Vietnamese power sector development analysis in the Balmorel modelling framework. This Technical Report is prepared in conjunction with a Data Report. The Data Report documents the data and assumptions used in the analysis and should be regarded as supporting documentation to the Technical Report.

The analyses are carried out using the Balmorel model, an open-source modelling framework, which has been populated with detailed data for the current Vietnamese electricity system and the expected future development. A fully functional setup of the final version of the Balmorel model, including all data files, is to be submitted to the MOIT and IE upon the completion of the project, for perpetual unlimited use.

The power system development pathways hereby presented are not to be regarded as forecasts; rather, as illustrations of potential implications of different alternative policy choices, subject to materialization of the underlying set of projections and assumptions.

All cost data in this report are USD 2015 real terms unless specifically stated otherwise.

Acknowledgements

The authors of this report would like to acknowledge the valuable input, comments and discussion provided by Jørgen Hvid (Danish Energy Agency), Tăng Thế Hùng (MOIT), and Nguyễn Ngọc Hưng (Institute of Energy) in the development and review of this report.

The authors would also like to express their gratitude to Vestas and the Danish Technical University for providing wind speed time series data for the current study.

Furthermore, keeping in mind the need for donor's coordination and avoiding duplicating efforts, the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH had agreed with the Danish Energy agency to join forces and provide both direct financing and specific input data. This cooperation intends to better fit the Balmorel study to the needs expressed by the General Directorate of Energy, Ministry of Industry and Trade.

Executive summary

The development of the Vietnamese electricity system has been studied from the current state and until year 2050. Least-cost model-based investment simulations using the Balmorel model, an open-source modelling framework, which has been populated with detailed data for the current Vietnamese electricity system and the expected future development, have been used to illustrate a number of possible futures.

Vietnam has committed to decrease the carbon footprint of the power sector through the goals set forth in the Renewable Energy Strategy. The report, firstly, explores the RE Strategy pathway in the Stated Policies scenario, and, secondly, sets forth scenarios representing different policy options to reaching this goal. The impacts and costs of the Stated Policies scenario and the scenarios based on alternative environmental policies (carbon pricing, carbon cap, future limitations to new coal-fired capacity build-out) are then compared to the least-cost business-as-usual pathway of no policy restrictions, i.e. the Unrestricted scenario. Finally, sensitivity analysis scenarios are presented to illustrate the least-cost optimal system development under the circumstances of variation in key external factors (power demand growth projections, fossil fuel prices, RE technology costs).

It is well understood that the input data projections towards year 2050 are subject to a high degree of uncertainty. The power system development pathways hereby presented are not to be regarded as forecasts; rather, as illustrations of potential implications of different alternative policy choices, subject to materialization of the underlying set of projections and assumptions.

RE integration

The analysis results indicate that it is possible to operate the Vietnamese electricity system with high levels of variable renewable energy. The dispatchable hydro generation capacity contributes to the system flexibility. The small amount of curtailment (no curtailment for solar PV and 4% curtailment for wind in 2040 in the Stated Policies scenario at 42 GW wind and 39 GW solar capacity in the system) indicates an efficient integration of wind and solar power in the system. Part of the reason for this is that all economic investment in transmission has been included which will contribute to accommodating the variable renewable energy.

Curtailment can be reduced further, e.g. with additional measures that presently have not been included in the analyses, like demand response and interchange with neighbouring countries.

Environmental policy alternatives

Under the assumption of absence of environmental policies or any other restrictions on power sector development (Unrestricted scenario), the modelling results indicate a highly coal-dominated power system in Vietnam towards 2050, which does not meet the RE Strategy goals and features high levels of CO_2 emissions.

The Stated Policies scenario, which features the RE Strategy goals as a requirement, exhibits significant shares of wind and solar PV generation, delivers CO_2 emission reductions, and does so at minor additional system cost. E.g. in 2040, the difference between Unrestricted and Stated Policies is 2 bn USD, or a 4% increase compared to the total costs of Unrestricted. In 2050, the corresponding values are 4.9 bn USD or 5.6% increase in costs. These can be interpreted as the additional (annualized) system costs for the implementation of the RE Strategy. The relatively little additional cost can be explained by the fact that while the Unrestricted scenario results in lower annualized generation capacity investment costs (Capital Cost) compared to Stated Policies, the latter realizes significant fuel expenditure savings (the higher-CapEx renewables, e.g. wind and solar PV, have no fuel costs).

CO_2 Cap consistently exhibits slightly lower total system costs than Stated Policies (0.38 bn USD in 2050), even though both scenarios achieve identical CO_2 emission levels. CO_2 Price High and No Coal, in turn, are characterized by the highest total system costs – whilst also having realized the lowest CO_2 emission levels.

It is a political decision whether these increases in cost are worth the outcome (e.g. lower emission levels). The analyses indicate how emission reduction can be achieved most efficiently, other things being equal.

Reliance on imported fuels

Absence of environmental policies (Unrestricted scenario) significantly increases the reliance on imported fuels, particularly imported coal. In the modelled results for 2050, the share of imported coal in the total coal use for power generation reaches 86% and amounts to 278 million tonnes. Compliance with the RE Strategy goals (Stated Policies scenario) reduces the coal import requirements in 2050 to 181 million tonnes (import share of 80% in total coal use for power generation). The most restrictive policy alternatives (CO_2

Price High and No Coal), in turn, result in the lowest volumes of imported fossil fuels required, due to largest shares of the power demand being covered by domestic renewable resources (88 and 37 million tonnes in 2050, respectively, and coal import shares of 66% and 45%, respectively).

RE resource potential

Land-based wind resource potential estimates have been based on the interim results of the wind resource mapping project supported by the GIZ in collaboration with the Danish Energy Agency, 'Macroeconomic Cost-Benefit Analysis for Renewable Energy Integration' (Ea Energy Analyses and DHI GRAS, 2017). Based on the preliminary results, significant feasible wind power potential is available in Vietnam (27 GW) – and further large potential is unlocked in the medium term if siting restrictions on croplands are removed (144 GW).

Competitiveness of RES (wind and solar PV)

The results indicate that already in the medium-term (i.e. towards 2030) significant investments in wind power capacity (exceeding 2.7 GW) could take place in Vietnam on cost-competitive basis, provided the materialization of continued RE technology cost reduction and improvements. The cumulative capacity of cost-competitive investments in wind and solar PV by 2050 in the Unrestricted scenario reaches 30 GW and 25 GW, respectively.

Electricity demand development

Whilst appreciating the high degree of uncertainty associated with making long-term projection of electricity demand, historical international perspective could be applied when evaluating the current power demand projections for Vietnam that are characterised by continuous high growth rates also in the long term. Structural shifts (away from energy-intensive heavy industries and towards more service-based economy) as well as advances in energy efficiency (both in industry and buildings, as well as in household appliances and lighting), among other drivers, have contributed to a disconnect between power demand and GDP growth observed globally, once a certain level of economic development has been achieved. In Vietnamese context, this could warrant (potentially significantly) lower power demand growth rate projections towards 2050.

Key take-aways

The key take-aways of the analysis are as follows:

- The results indicate that the Vietnamese power system could successfully integrate very significant shares of RES generation

  - Transmission capabilities play an important role in successful RES integration – the results include significant investments in additional transmission capacity
  - Further RE integration measures could be considered that are not currently implemented in the scenario analyses, e.g. demand response and regional interconnections
- Economic results indicate the RE Strategy goals could be achieved at a relatively modest additional cost compared to the business-as-usual scenario ('Unrestricted')
  - Higher capital expenditure of the RE capacity is partially outweighed by lower fossil fuel expenditure
- The best wind resource areas (exceeding 2.7 GW) could become cost competitive with conventional power generation sources by 2030, provided the projected continued RE technology cost reductions and performance improvements
  - By 2050, cost-competitive cumulative capacity of wind and solar reaches 30 GW and 25 GW, respectively
- Reliance on imported fuels is higher in scenarios with less ambitious environmental and RE policies
  - Utilisation of the domestic RE resources reduces the need for imported fossil fuels
  - The domestic coal and natural gas resources are not sufficient to fully cover the growing electricity demand
- Based on preliminary results[1], significant feasible wind power potential is available in Vietnam (27 GW) – and further large potential is unlocked if siting restrictions on croplands are removed (reaching 144 GW)
  - The current results indicate that the RE Strategy goals towards 2030 could be reached and exceeded while complying with the present planning regulations
- Implications of different policy choices:
  - RE targets do not directly affect the rest of the system thereby delivering more limited impact on CO2 emissions (e.g. carbon-intensive power generation technologies such as coal-fired power plants are not directly addressed through RE targets)

[1] Interim results of the wind resource mapping project supported by the GIZ in collaboration with the Danish Energy Agency, 'Macroeconomic Cost-Benefit Analysis for Renewable Energy Integration' (Ea Energy Analyses and DHI GRAS, 2017).

- Policies addressing CO_2 emissions / costs directly could more efficiently achieve CO_2 emission reduction ambitions (e.g. CO_2 cap or CO_2 price)
- Intuitively, 'No Coal' scenario identifies the most critical driver of CO_2 emissions
  - Results suggest the Vietnamese power system could successfully operate without additional coal-fired generation beyond 2035, but there will be additional costs

- Importance of the planning assumptions for the development of the power system – and their respective implications
  - Electricity demand growth is a very important planning assumption (affecting system size, setup, costs and CO_2 emissions) that should be critically evaluated, considering international experience and prospective developments in e.g. structural shifts and advancements in energy efficiency
  - Lower natural gas price projections would favour gas-fired generation over coal, and deliver CO_2 emission reductions
  - RE technology cost developments could lead to more competitive wind and solar PV in Vietnam, affecting the optimal setup of the surrounding conventional system

1 The Balmorel model

The Balmorel power system model is an economic and technical partial equilibrium model that simulates the power system and least-cost dispatch. The model optimises the production at the existing and planned production units and simultaneously simulates investments in new generation and transmission. Investments are also made on a cost-minimising basis and they can include constraints on availability of fuels, cap on transmission investments, etc. Output of Balmorel model is least-cost investment in generation and transmission infrastructure with an optimal dispatch. Figure 1 provides an overview of the operational structure of the Balmorel model.

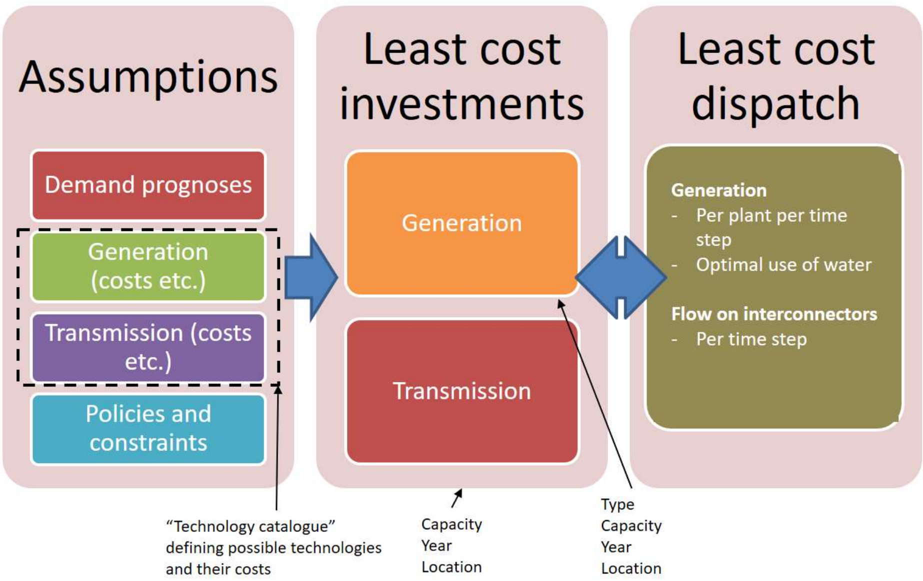


Figure 1: Schematic overview of the Balmorel model operational structure

Balmorel is a deterministic model that finds optimal solutions based on given inputs. All information is used in the form of "perfect foresight" within a given year. This simplification gives two important benefits:

- It is easy to compare alternative scenarios. All solutions are least-cost, and any difference in the results is a result of the change in input.
- Computation time is significantly decreased.

The model is flexible and can be used in several different setups:

- Optimal dispatch with a certain specification of generation and transmission (fixed system)
- Allow investment in generation and transmission

- Use extra detailed information about power system dynamic, e.g. unit commitment of specific plants and information about ramp rates, minimum generation levels and minimum hydro flow.
- A limited number of time steps can be used to represent the year, or a full hourly resolution can be used.

The model can invest in generation if the value of the generated electricity over the year exceeds the additional costs incurred in the given year (annualised cost of the investment plus fuel and O&M costs).
The same principle applies to transmission investments. The model can invest in transmission if the reduction in total regional cost is reduced more than the annualised investment costs for the line (including losses and O&M costs).
The transmission lines are represented by the total capacity between areas. Other models are more detailed, but will then have neighbouring areas represented in a simplified way or will only simulate selected operational mode, e.g. peak load.

The model is open source, meaning the user has full access to the data and the equations (see www.balmorel.com).

The Balmorel model in Vietnam

The Balmorel model has first been introduced to the Vietnamese energy sector experts in July 2015, as a part of the activities organized by the Danish-Vietnamese cooperation between the Danish Energy Agency, the Danish Embassy in Vietnam and the Ministry of Industry and Trade of Vietnam. First capacity-building and training activities in the use of the Balmorel model for the Vietnamese energy experts were commenced in October 2015. Thereafter, continuous data and model updates and operator training has been carried out in close collaboration with the Institute of Energy in HaNoi. Fully functional Balmorel model setup (including operational model, all data files and the user licences for the GAMS solver) has been installed on a server at the Institute of Energy for free and perpetual use.

The Balmorel model is one of the modelling frameworks available for long-term power system planning studies. Compared to the present modelling frameworks used for power system planning in Vietnam, the Balmorel model has distinct advantages:

- The optimisation is done simultaneously for investment in generation capacity and transmission capacity (not separately)

- The optimal investments in generation and transmission capacity are done in parallel to optimal dispatch, and hourly dispatch (with full representation of operational limitations of conventional power plants and unit commitment) can be done within the same modelling framework and setup
- The Balmorel model is well suited for analyses of RE integration in the power system because it uses hourly load variation profiles, hourly wind power wind speed time series (for different locations), hourly solar PV generation profiles (for different locations), as well as represents the variability and storage capabilities of hydro power plants

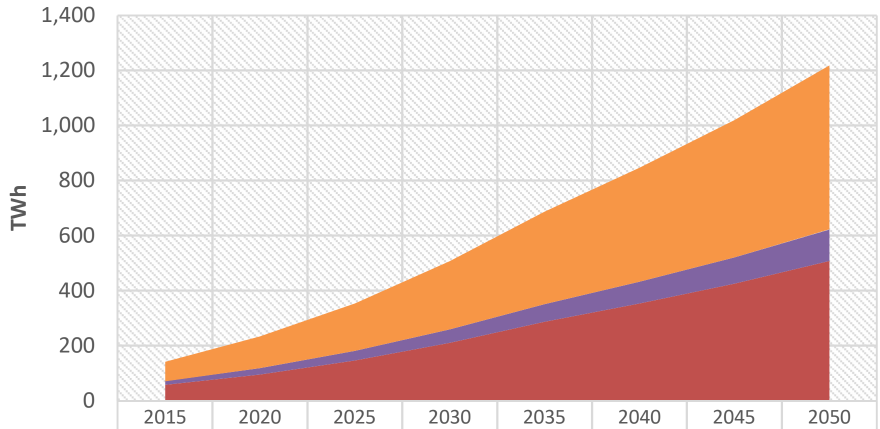
Finally, the Balmorel model is free (only a user licence for a commercial solver is required), and all of the equations and optimisation mechanisms are fully visible to the user. Improvements and additional functionalities can also be added to the model by the user, making it both affordable and versatile, and open for joint use by several institutions in parallel.

2 Key input data and assumptions

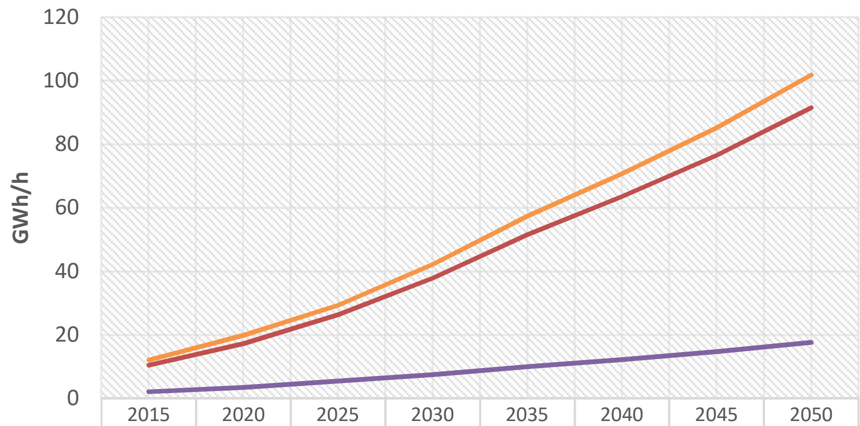
This section will provide a top-level overview and discuss the key input categories, as well as present the main limitations of the analysis. Detailed documentation of the input data and assumptions used in the analysis is provided in the supporting Data Report (Ea Energy Analyses, 2017).

Power demand projections

The power demand projections used in this study, presented in Figure 2, are supplied by Institute of Energy, and are in line with the demand forecasts used in the PDP 7 revised throughout 2035. Projection towards 2050 is based on the Energy Development Plan (work-in-progress version as of December 2016) and derived by extrapolation of economic growth projection for the respective period. It should be noted that the assumption of electricity intensity per unit of GDP is reduced significantly in the long-term power demand projection period.



	2015	2020	2025	2030	2035	2040	2045	2050
South	71	116	171	247	336	414	499	596
Center	13	22	35	49	64	79	96	114
North	58	95	146	210	286	352	425	508



	2015	2020	2025	2030	2035	2040	2045	2050
North	10.4	17.2	26.3	37.9	51.6	63.6	76.6	91.5
Center	2.1	3.4	5.4	7.5	9.9	12.2	14.7	17.6
South	12.1	19.8	29.3	42.2	57.4	70.7	85.2	101.9

Figure 2: Annual electricity demands per control region (above) and peak demands per control region (below).

The current demand projections feature rapid and continuous growth, the total electricity demand forecasted to increase more than six-fold by 2050. Due to the uncertainty associated with making long-term projections, and the critical role of electricity demand forecasts in power system planning, it is important to consider alternative demand development pathways (High and Low electricity demand scenarios are presented in Sensitivity analyses section). At the same time, it is helpful to regard the current power demand projections in historic international context.

Electricity intensity and GDP growth

Figure 3 illustrates the historic development of electricity consumption per dollar of GDP plotted against GDP per capita over the 1980-2012 period across the globe (please note both X and Y scales are logarithmic). Each 'dot' on the graph represents the value for the given country/region in one year, hence the pattern of the dots illustrates the development over time. (The data for Vietnam is additionally included, covering the 1989-2012 period, designated by the hollow blue dots.) The historic development paints a relatively robust picture of initial increase of power-use-per-GDP along with increasing GDP per capita, followed by a disconnect between the two. GDP per capita in Vietnam in 2015 has been estimated at 2111 USD (World Bank, 2017), equivalent to 1910 USD in 2009 real terms.

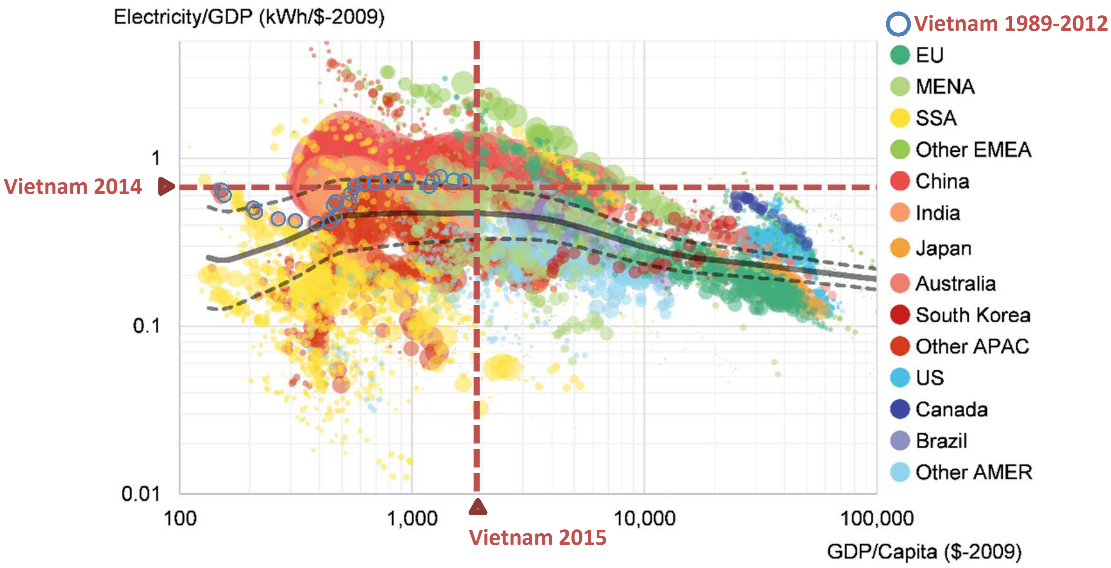


Figure 3: Electricity consumption per GDP plotted against GDP per capita, 1980-2012. Illustration source: (Bloomberg New Energy Finance, 2015). Data sources: Bloomberg New Energy Finance, IMF, World Bank, EIA, Eurostat, US Census Bureau, US Bureau of Economic Analysis. Blue hollow circles represent Vietnam (1989 – 2012), based on World Bank data. Note: Size of bubble is representative of country population (except for Vietnam). Both X and Y scales are logarithmic. EU=European Union, MENA=Middle East and North Africa, SSA=Sub-Saharan Africa

The historic data appears to suggest that, once a certain level of economic development is reached in a country (the absolute levels may vary), further GDP growth may not result in corresponding growth in power demand. E.g. according to the IEA data, electricity supplied in the OECD countries in 2014 as compared to 2007 decreased by 0.4%, whilst the economic growth in the OECD area reached 6.3% in the same period (Bloomberg New Energy Finance, 2015).

The ‘peak’ electricity use per unit of GDP appears to be shifting over time, however, as illustrated by Figure 4 (each line represents the average electricity/GDP curve of a 2-year period, starting from historic as of 2002, and ending with a projection for 2022, represented by the lowest green line). In 2002, the level of GDP per capita that would correspond to the global average ‘peak’ (i.e. further increase in GDP after this point would not be coupled with corresponding growth in electricity use) was ca. 2000 USD per capita; presently this ‘peak’ is observed at ca. 8000 USD per capita in 2009 USD real values (equivalent to ca. 2210 and 8840 USD 2015 real values, respectively) (Bloomberg New Energy Finance, 2015).

BNEF analysis furthermore suggests the ‘peak’ would remain at ca 8840 USD (real 2015 values) towards 2022, and projecting more modest electricity demand growth rates globally – whilst acknowledging other authoritative sources (e.g. IEA’s WEO and ExxonMobil’s Outlook for Energy) that forecast e.g. 85% increase in power demand globally by 2040 (Bloomberg New Energy Finance, 2015).

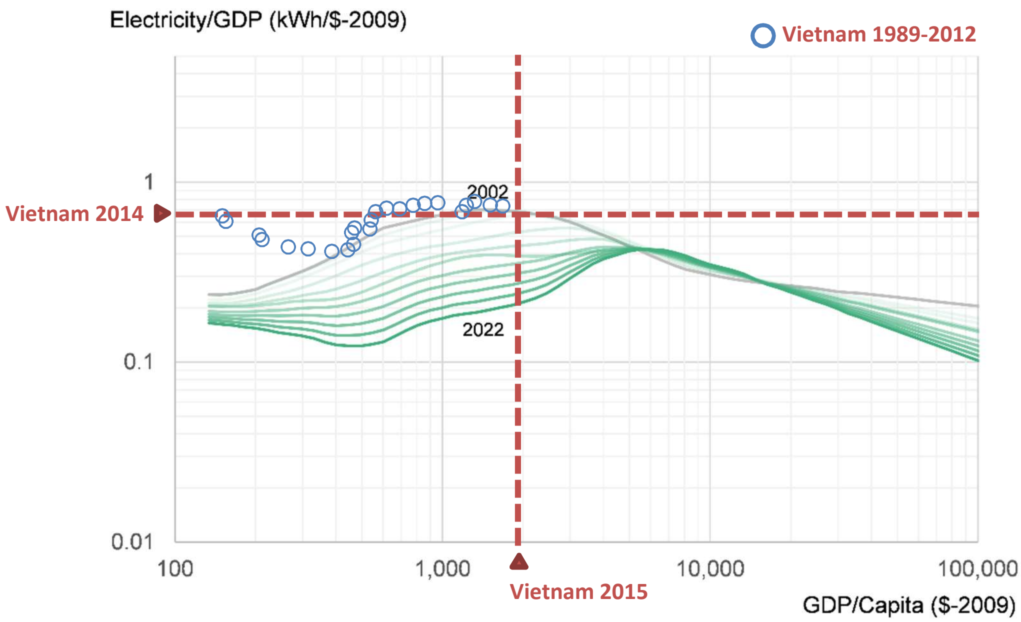


Figure 4: Electricity consumption per GDP plotted against GDP per capita, average, 2002-2022 (including projections). Blue hollow circles represent Vietnam (1989 – 2012), based on World Bank data. Illustration source: (Bloomberg New Energy Finance, 2015).
Note: Both X and Y scales are logarithmic.

Whilst appreciating the high degree of uncertainty associated with making long-term projection of electricity demand, this historical perspective could be applied when evaluating the current power demand projections for Vietnam:

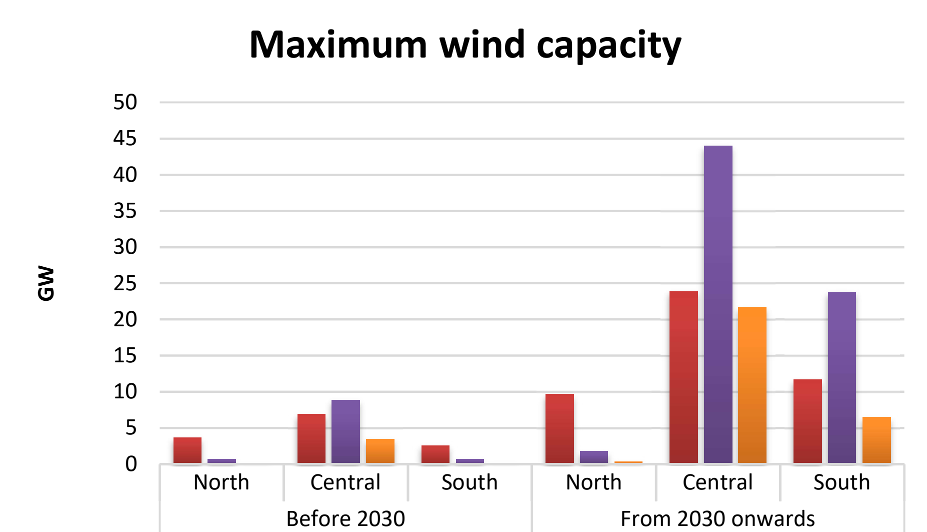
to assess whether Vietnam would likely have reached the level of economic development prompting the ‘disconnect’ between power demand and GDP growth before 2050. This, in turn, could translate in lower power demand growth rate projections towards 2050.

RE resource potential estimates

This section briefly outlines the main assumptions used in the model in relation to RE resource potentials in Vietnam. Please refer to the supporting Data Report for full description of the modelling data and assumptions (Ea Energy Analyses, 2017).

Wind power

Land-based wind resource potential estimates have been based on the interim results of the wind resource mapping project supported by the GIZ in collaboration with the Danish Energy Agency, ‘Macroeconomic Cost-Benefit Analysis for Renewable Energy Integration’ (Ea Energy Analyses and DHI GRAS, 2017), illustrated in Figure 5. No offshore wind resources are currently implemented in the model.



	Before 2030			From 2030 onwards		
	North	Central	South	North	Central	South
Low	3.7	6.9	2.6	9.7	23.9	11.7
Medium	0.7	8.9	0.7	1.8	44.0	23.8
High	0.1	3.5	0.1	0.4	21.7	6.5

Figure 5: Resource limits per region and on wind speed class implemented in the Balmorel model. Low: 4.5-5.4 m/s, Medium: 5.4-6.18 m/s, High: over 6.18.

In the medium term (i.e. towards 2030), the wind resource potential represented in the model is comprised of areas suitable for wind power development (based on wind resource quality, topology, population density, protected area etc. exclusion criteria) that are within 10km distance both from roads and high-voltage transmission grid infrastructure. Croplands are excluded from the medium-term wind power resource potential area. The national land-based wind resource potential towards 2030 represented in the model is thereby 27 GW. 2030 onwards, area within 20km distance both from existing road and existing high-voltage transmission grid infrastructure is considered feasible for wind power development without significant additional capital expenditure (both road and transmission grid networks are likely to develop considerably during the period). In addition, croplands are also included as potential siting areas. The cumulative national potential is thereby reaching 144 GW in the long term.

The national resource potential estimates are then divided across the regions and wind resource classes to be implemented in the model. In order to represent the intermittent and variable nature of wind resource, hourly wind speed time series per regional wind class are used in the model. Within the framework of the current study, hourly wind speed time series have been kindly provided by Vestas, as well as DTU Vindenergi (work-in-progress output from the wind resource mapping component of the activity Resource Mapping and Geospatial Planning Vietnam under contract to The World Bank). Hourly wind speed time series of a 'normal' wind year (i.e. the year with the median annual average wind speed out of a sample of 9 modelled years) have been selected to be used in the model.

Solar PV

There is high degree of uncertainty associated with the available technical / commercial wind and solar PV potential available in Vietnam. A comprehensive solar PV resource mapping project led by World Bank is on-going at the time of writing this report.

Presently, a technical solar PV resource estimate based on a study commissioned by the Spanish Agency for International Development Cooperation (AECID) and available on the ESMAP website has been used in the analysis (CIEMAT, CENER and IDAE). The technical potential therein has been delimited to comprise only of the areas suitable for solar PV plant siting (according to the exclusion criteria of the AECID study) within 10km distance both from existing roads and high-voltage transmission grid infrastructure. The resulting regional solar PV resource potentials are presented in Figure 6.

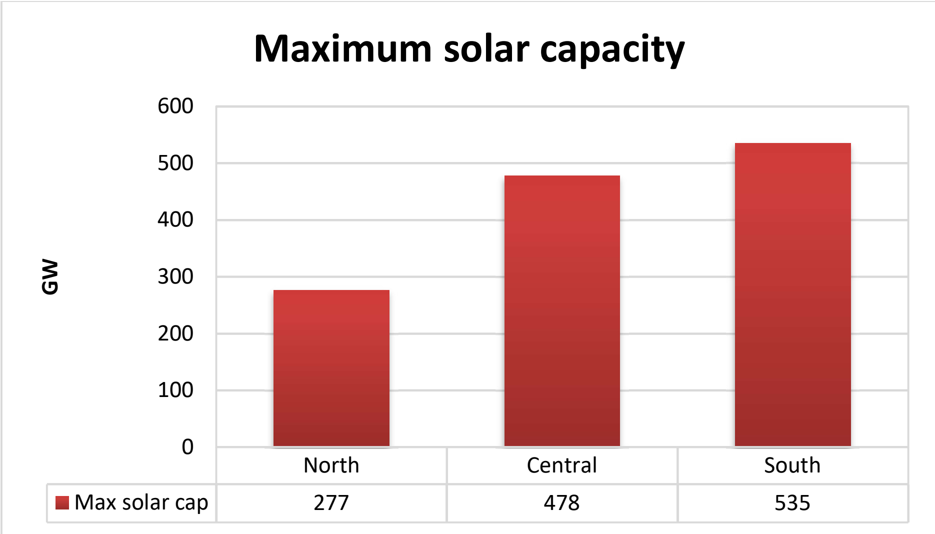


Figure 6: Regional solar PV resource potentials

Though the resulting solar PV resource potential in Vietnam is very high, it should, however, be noted that the exclusion criteria applied in the AECID study have not been fully comprehensive (e.g. protected areas and land use limitations have not been considered). Hence, a revision of the solar PV potential estimate would be recommended in line with the results of the presently on-going World Bank solar resource mapping study.

Other renewables

The small hydro capacity resource potential per region has been provided by IE (Institute of Energy), as presented in Figure 7.

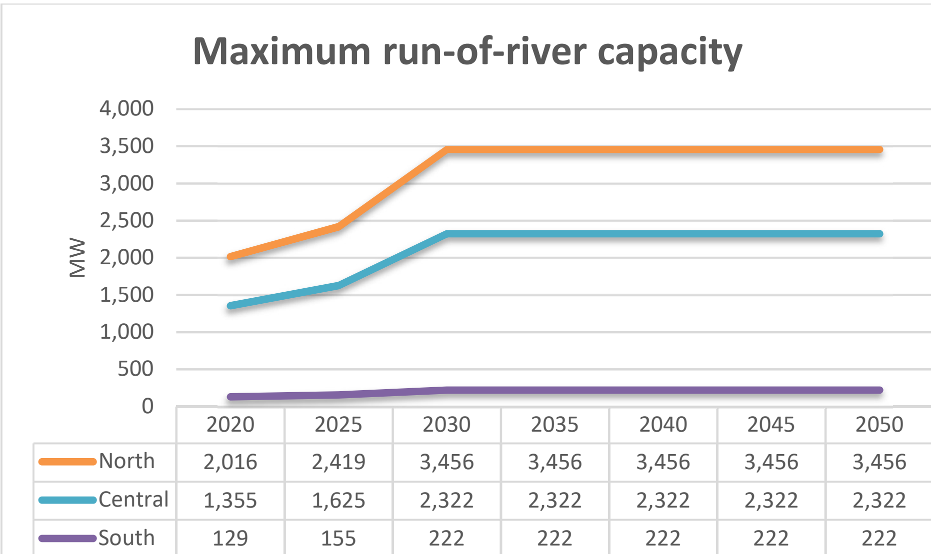


Figure 7: Resource limits for small hydro capacity per region implemented in the Balmorel model

The biomass resource potential available for use in power generation has been estimated to reach 2100 MW (Institute of Energy), as presented in Figure 8. It should, however, be noted that the biomass resource potential estimates might be subject to change in accordance with the outcome of the currently on-going biomass resource mapping project by GIZ.

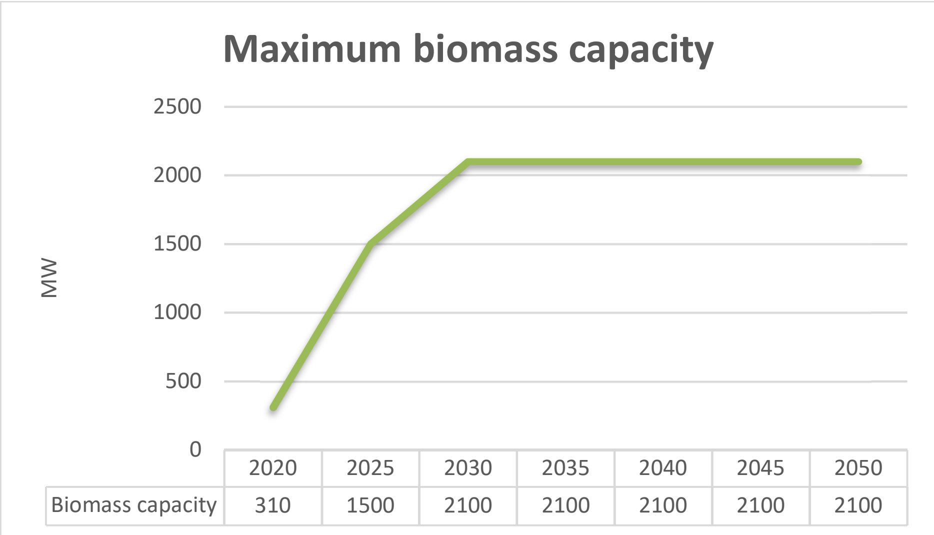


Figure 8: Resource limits on biomass-fired power generation capacity implemented in the Balmorel model

RE power plant investment cost projections

The central assumptions regarding the RE power plant investment costs – and future developments thereof - are based on credible international and local sources: (IEA, 2016), (GIZ, 2015), (Task 26, 2015) and (IE, Institute of Energy). The technology catalogue for RE technologies is provided in Table 1.

Technology type	Available (Year)	CAPEX incl. IDC ($1000/MW el.)	Fixed O&M ($1000/MW el.)	Variable O&M ($/MWhel.)	Efficiency (%)	Technical lifetime (Years)
Geothermal	2020 - 2050	2,171	21.75	0.49	25%	20
Rice Husk	2020 - 2050	2,121	50.03	-	32%	20
Straw	2020 - 2050	1,903	32.63	-	32%	20
Bagasse	2020 - 2050	1,468	44.59	-	32%	20
Wood	2020 - 2050	2,121	56.56	-	32%	20
MSW	2020 - 2050	4,895	56.56	-	32%	20
Pumped storage	2025 - 2050	1,088	-	-	70%	40
Small hydro	2020 - 2050	1,800	-	-	*FLHs*	40
Tidal	2020 - 2050	2,961	21.75	-	*FLHs*	30
Wind	2020 - 2024	1,971	28.84	3.02	*FLHs*	20

Wind	2025 - 2029	1,813	27.87	2.90	*FLHs*	20
Wind	2030 - 2039	1,656	26.91	2.78	*FLHs*	20
Wind	2040 - 2049	1,555	26.25	2.65	*FLHs*	20
Wind	2050	1,454	25.58	2.53	*FLHs*	20
Solar PV large scale	2020 - 2024	1,119	7.31	1.13	*FLHs*	20
Solar PV large scale	2025 - 2029	1,022	6.55	1.00	*FLHs*	20
Solar PV large scale	2030 - 2039	925	5.79	0.88	*FLHs*	20
Solar PV large scale	2040 - 2049	839	5.17	0.80	*FLHs*	20
Solar PV large scale	2050	753	4.55	0.72	*FLHs*	20
Solar PV rooftop	2020 - 2024	1,344	7.31	1.13	*FLHs*	20
Solar PV rooftop	2025 - 2029	1,239	6.55	1.00	*FLHs*	20
Solar PV rooftop	2030 - 2039	1,134	5.79	0.88	*FLHs*	20
Solar PV rooftop	2040 - 2049	1,029	5.17	0.80	*FLHs*	20
Solar PV rooftop	2050	945	4.55	0.72	*FLHs*	20

Table 1: Power generation technology catalogue.

For wind power plant investment costs, a convergence from Vietnamese investment costs (GIZ, 2015) to international investment costs (IEA Wind Task 26, 2016) is implemented. Investments from (IEA, 2016) – New Policies, are implemented for large scale PV and PV on buildings (for 2050, the year 2040 in the 450-ppm scenario is used). The learning curves for wind and solar are also illustrated in Figure 9. Biomass investments costs for Vietnam are based on (GIZ). Investment costs for pumped storage, geothermal, MSW and small hydro are obtained from (IE, Institute of Energy).

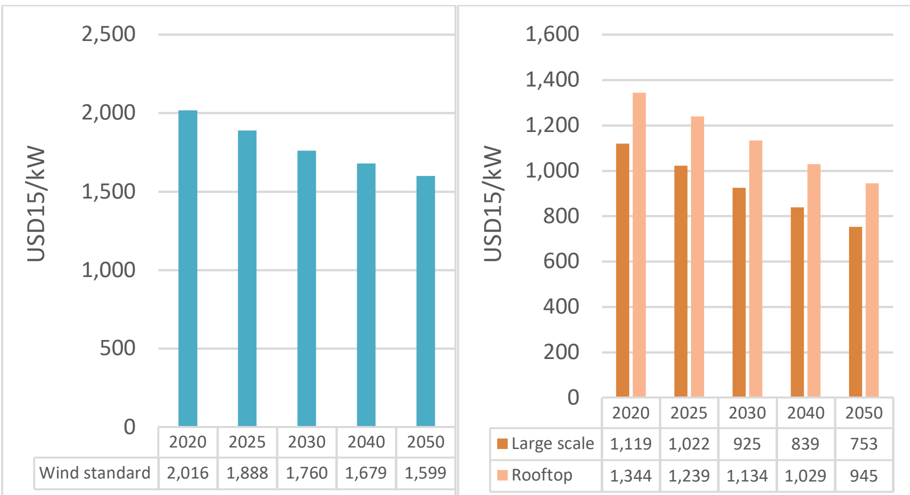


Figure 9: Learning curves wind and solar, Investment costs including IDC (USD2015/kW)

However, in light of the very steep and game-changing RE cost reductions having taken place in the recent years (which were broadly not anticipated), it becomes relevant to investigate the optimal power system development pathway under different, more ambitious future RE cost reduction development.

This development pathway is incorporated in the Low RE Costs scenario, presented in the Sensitivity analyses section of this report.

Limitations of the Balmorel model analysis

Power system representation in a modelling setup, as well as creation of possible future developments therein, entails certain assumptions and simplifications. The following limitations should be considered when regarding the results of the current study:

- Uncertainty of the inputs: large degree of uncertainty is associated with future projections of the key input parameters (fuel and technology costs, technology performance and developments, electricity demand etc.). The results of the analysis will be directly subject to the accuracy of the input parameters (the impact of some of the uncertainty is addressed in the Sensitivity analyses section).
- The Balmorel model assumes a number of simplifications in order to ensure the optimization time and complexity could be minimized. The simplifications include perfect foresight (i.e. the model 'knows in advance' the exact hourly demand and intermittent power source generation profiles, and does not make reserve margin allocations by default) and the assumption of perfect competition in the market (i.e. all power is offered at short-term marginal cost and no exercise of market power is taking place, as well as dispatch taking place under perfect merit-order dispatch conditions).
- The Balmorel model represents power supply in great detail (up to individual power plant level) and simulates rational behaviour. The representation and physical characteristics of power grids and flows are, however, simplified. E.g. each 'region' represented in the model is considered a copper plate (only transmission capacities between different regions are represented) and the inter-regional power flows are limited by the maximum constant transmission capacity – detailed operational aspects as N-1 and voltage limits (e.g. Kirchoff laws) are not considered).
- The Balmorel model considers the necessary investment requirements in inter-regional (high voltage) transmission capacity. However, the costs associated with e.g. surrounding transmission network strengthening are not included.
- Furthermore, each investment decision in the model is taken based on the individual year the scenario is modelled for (based on the modelled 'income' from power sales and the annualized investment costs -

and the fixed operational costs), and the same annuity factor is assumed across all investment technologies (based on the assumption of 10% interest rate and 20-year payback period).

- Finally, the flexibility of conventional power plants (unit commitment, start-up and shut-down time etc.) is not restricted in the simulations generating investment decisions. The dispatch is thereafter tested in an hourly simulation with unit commitment restrictions applied (please see Integration of renewables and dispatch section).

3 Scenarios

The scenarios explore potential policy alternatives (or absence thereof) on the basis of the present and near-term committed power system of Vietnam. A separate scenario is dedicated to the power system expansion plan as projected by the PDP 7 revised. Figure 10 provides an overview of the scenarios implemented in the current analysis.

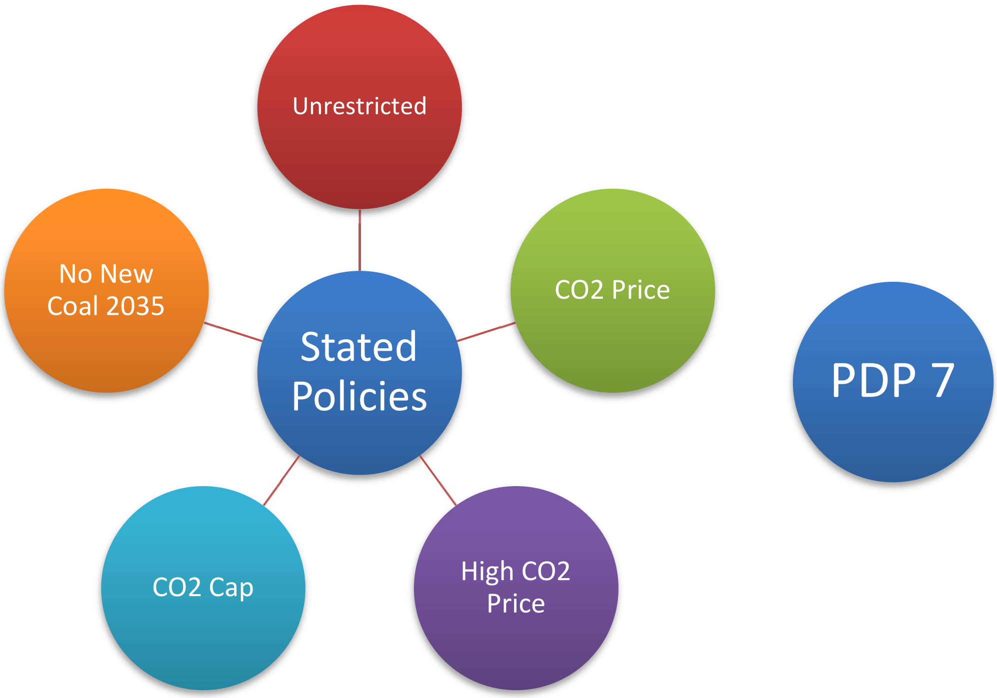


Figure 10: Overview of the scenarios implemented in the analysis

PDP 7

The PDP 7 scenario implements the entire power and transmission system development plan as laid out by PDP 7 revised towards 2030. The key features of the scenario are as follows:

- PDP 7 revised generation and transmission capacity is represented until 2030
- No model-based investments (dispatch modelling only)
- Runs in 5-year periods until 2030
- No RE goal requirement implemented

Stated Policies

The Stated Policies scenario is based on PDP 7 revised power system development plan in the near term, while allowing model-based investments in generation and transmission thereafter. The model-based optimisation uses input data and assumptions that are based on best available information, and is required to comply with binding national policies (e.g. the RE goals). The key features of the scenario are as follows:

- PDP 7 revised generation and transmission capacity is represented until 2020
- Model-based investments are allowed:
  - In generation capacity - from 2020
  - In transmission capacity - from 2030
- Runs in 5-year periods until 2050
- RE goal requirements implemented in line with RE Strategy, as presented in Figure 11

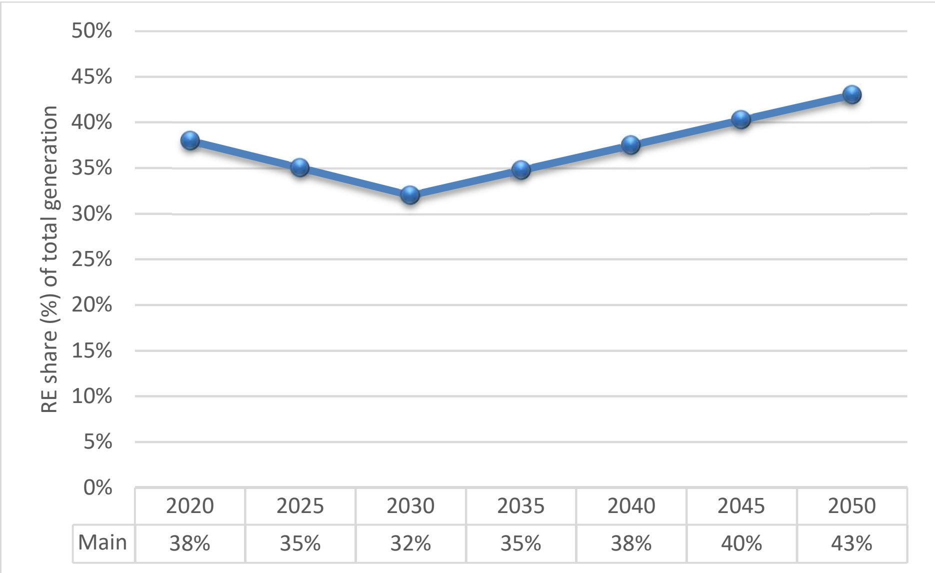


Figure 11: RE goal requirements including large hydro (in line with the RE Strategy) implemented in the Stated Policies scenario, as a required share of total generation

Alternative scenarios

The alternative scenarios are all based on the Stated Policies scenario and are designed such that only one parameter is varied compared to the Stated Policies scenario. I.e. any and all differences in outcomes in the alternative scenario vis-à-vis the Stated Policies scenario can be attributed to the change in the single parameter.

The following characteristics are shared across all alternative scenarios:

- PDP 7 revised generation and transmission capacity is represented until 2020
- Model-based investments are allowed:
  - In generation capacity - from 2020
  - In transmission capacity - from 2030
- Runs in 5-year periods until 2050

The following sections present the alternative scenarios and their differences vis-à-vis the Stated Policies scenario.

Unrestricted

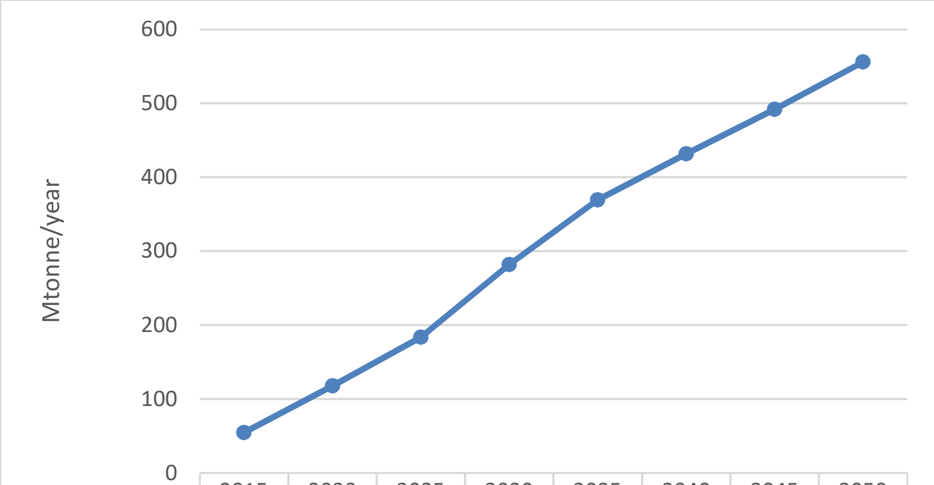
The Unrestricted scenario represents a very hypothetical future perspective wherein no environmental or RE policies are being pursued. This can, however, be used as a baseline to evaluate the difference made by the various alternative policies investigated. The parameter variation of the scenario vis-a-vis the Stated Policies scenario is as follows:

- No RE goal requirement implemented

CO_2 Cap

The CO2 Cap scenario is the 'CO2 emission equivalent' scenario of the Stated Policies scenario. CO2 Cap scenario investigates the implications of substituting the RE goals with a CO2-focused policy, wherein a limitation is set on the total power system CO2 emission level. This also allows for the calculation of CO2 emission shadow price. The parameter variations of the scenario vis-a-vis the Stated Policies scenario are as follows:

- CO2 emission cap is introduced in line with the CO2 emission level generated in the Stated Policies scenario
- No RE goal requirement implemented



	2015	2020	2025	2030	2035	2040	2045	2050
CO2 emissions	55	118	184	282	370	432	492	556

Figure 12: CO2 emission level pathway in the Stated Policies scenario (million tonnes CO2 emission)

CO2 Price

The CO2 Price scenario represents an environmental policy alternative to the RE goals, wherein CO2 emissions are associated with an additional cost (which can be interpreted as CO2 price, CO2 planning value, CO2 tax etc.). The parameter variations of the scenario vis-a-vis the Stated Policies scenario are as follows:

- A CO2 price is implemented: 7 USD/tonne in 2020, 20 USD/tonne thereafter (see Figure 13)
    - Based on estimated CO2 externality value in Vietnam (Nguyen-Trinh & Ha-Duong, 2015)
- No RE goal requirement implemented

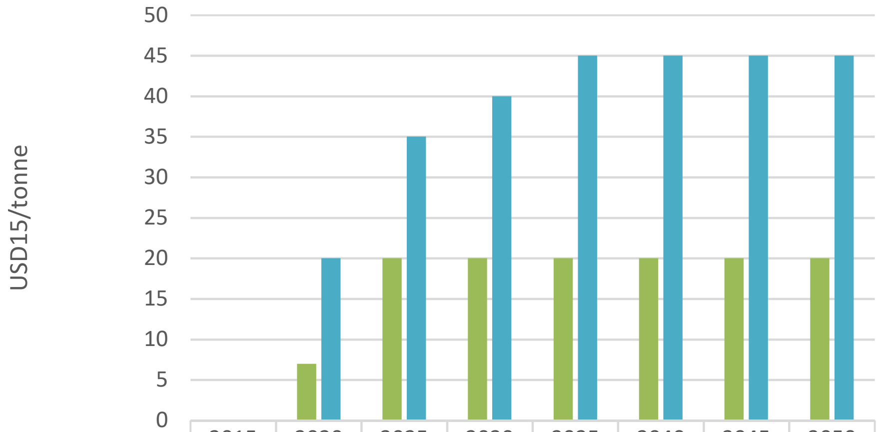
Selection of CO2 price for the scenario

The CO2 price level of 7 USD/tonne in 2020, 20 USD/tonne thereafter was set based on the study 'Low Carbon Scenario for the Power Sector of Vietnam: Externality and Comparison Approach' by H.A Nguyen-Trinh and M. Ha-Duong. In the study (Nguyen-Trinh & Ha-Duong, 2015), damage costs of CO2 were calculated based on CO2 prices of Clean Development Mechanism (CDM) projects in Vietnam. US$7/ton was the value corresponding to the monetary benefits that power producers could earn if they reduced CO2 emission in electricity generation, and deemed approporate for historical and near-term calculations. For long-term projections, the study sets forth average CO2 externality cost of US$ 20/ton.

CO2 Price High

The CO2 Price High scenario is a variation of the CO2 Price scenario, wherein the level of costs associated with CO2 emissions are higher than in the CO2 Price scenario. The parameter variations of the scenario vis-a-vis the Stated Policies scenario are as follows:

- A higher CO2 price is implemented, as presented in Figure 13
- No RE goal requirement implemented



	2015	2020	2025	2030	2035	2040	2045	2050
CO2 price	0	7	20	20	20	20	20	20
CO2 price high	0	20	35	40	45	45	45	45

Figure 13: CO2 price levels represented in the CO2 Price scenario and CO2 Price High scenario, respectively (USD 2015/tonne CO2)

Selection of CO2 price for the scenario

The CO2 price levels for the CO2 Price High scenario were selected such that they would exhibit a significantly more ambitious environmental policy pathway than the Stated Policies scenario. With the implied CO2 *shadow prices*[2] of the Stated Policies scenario as the starting point, additional CO2 cost of ca 20 USD/tonne was added to the resulting CO2 shadow price levels within each year modelled (for years 2030 and 2035 the cost add-on was though ca 35 USD/tonne in order to maintain CO2 price growth trend in the CO2 Price High scenario, whilst the CO2 shadow prices for the Stated Policies scenario were decreasing in the respective period).

[2] The CO2 shadow price can be interpreted as the equivalent of a tax that should be added to fuels, to realise the required (low) emission level in the Stated Policies scenario, or the subsidy given to clean energy to reach the clean energy goal (in the absence of the RE goals). In the current study, due to the modelling setup, the CO2 shadow prices were obtained using the CO2 Cap scenario (CO2 emissions of which were identical to those of the Stated Policies scenario)

No New Coal

The No New Coal scenario represents an ambitious, hypothetical environmental policy alternative whereby the expansion of coal-fired power generation capacity is stopped 2035 onwards (whilst allowing the existing coal-fired power plants to remain operational also beyond 2035). The No Coal scenario is comprised of the Stated Policies scenario with an addition of a restriction on new coal-fired power plant construction as of 2035. Investments in CCS coal-fired technology would still be permitted. The parameter variation of the scenario vis-a-vis the Stated Policies scenario is as follows:

- No new investments in coal-fired technology allowed as of 2035

4 Modelling results

This section presents the modelling results of the scenarios within the Balmorel modelling framework.

PDP 7 and Main

Figure 14 provides an overview of the development of the power generation capacity fleet in Vietnam towards 2030 in line with the PDP 7 revised. No additional model-based investments have been made in the PDP 7 scenario.

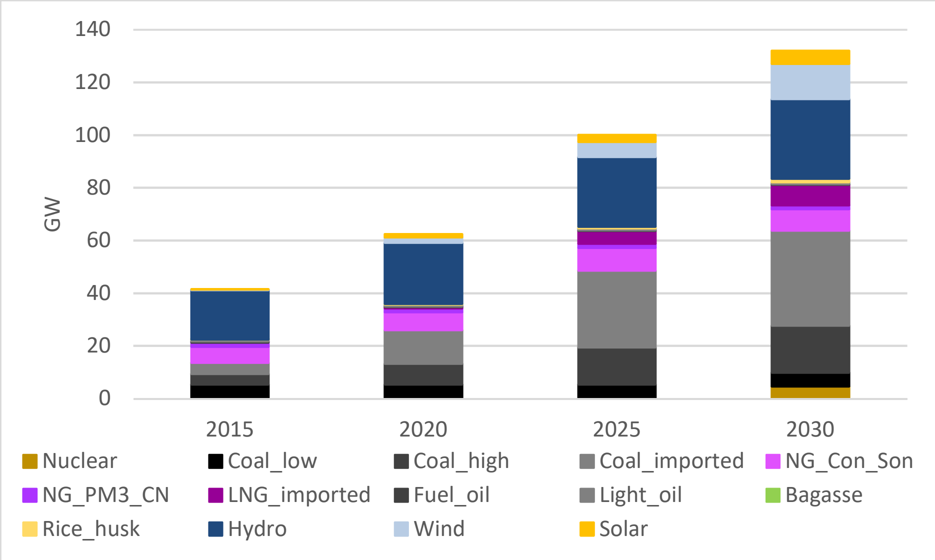


Figure 14: Power generation fleet development as projected by the PDP 7 revised (see Appendix IIa and IIb for detailed data tables)

As the graph illustrated, PDP 7 revised projects very significant increase in coal-fired capacity in Vietnam – from under 14 GW in 2015 to almost 60 GW in 2030. The majority of this additional capacity is based on imported coal. Gradual increase in renewable energy capacity is also projected, reaching over 13 GW wind and almost 5 GW solar by 2030.

In order to explore potential 'alternative futures' for the development of the Vietnamese power system, whilst respecting the existing and committed system developments, a different approach is taken in the other scenarios in this analysis. In the Stated Policies scenario (and all other scenarios and sensitivity analyses), the point of departure is the existing system, as well as the near-terms power system developments as projected by the PDP 7 revised (towards and including 2020). Thereafter the model is given freedom to develop the system in the least-cost manner given the individual scenario policies and requirements. The generation fleet ‘starting point’ (i.e. the existing and committed system towards 2020) is presented in Figure 15.

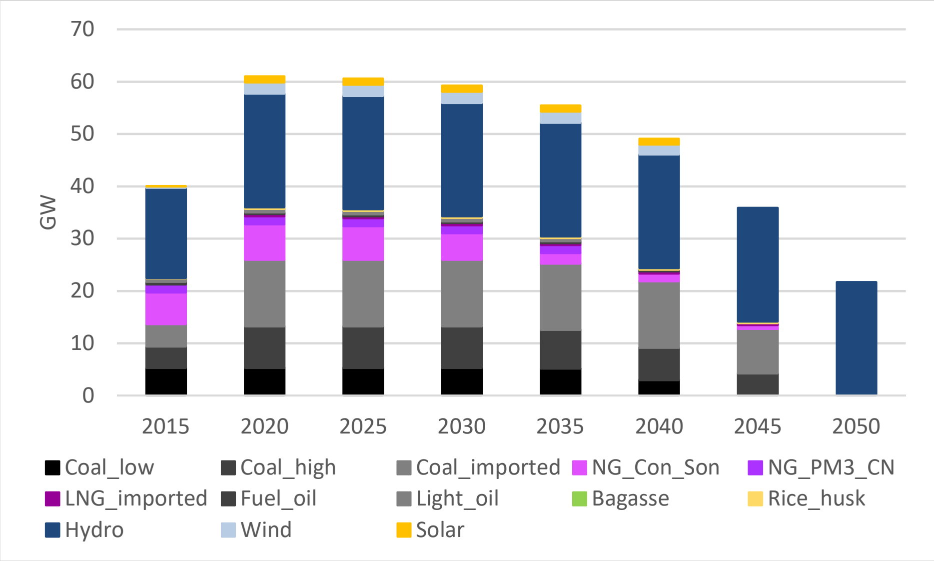


Figure 15: Existing and committed generation capacity for the Stated policies as well as all scenarios (except PDP 7) and sensitivities. Model-based generation capacity investments take place in addition to the existing and committed generation fleet

As it can be observed in the figure, the ‘existing and committed’ generation capacity declines over time, in line with the economic lifetime assumptions in the model (decommissioning).

Reserve margin

The Stated Policies scenario (and its alternative scenarios) do not directly incorporate reserve margin. Provision for plant downtime is made through limiting generation plant capacity availability to 90% at any given time. Apart from that, the model-based investments and dispatch are carried out under perfect foresight.

Reserve margin is not implemented in the core scenarios modelled because system adequacy and reliability considerations are beyond the scope of the current study. The present analysis does not intend to put forward a recommendation regarding the optimal system adequacy requirements for Vietnam; rather, a sensitivity analysis including a reserve margin is hereby performed (presented below) to assess the impact thereof. Provisions for reserve margin would, however, be relatively uniform across the different scenarios if implemented. The conventional approaches towards system adequacy (based on peak load or the ‘n-1’ criterion) would likely be constant across the scenarios, with the exception of power demand variation scenarios. Hence, exclusion of reserve margin provisions does not hinder analysis based on comparison across the different scenarios. Stochastic analyses of system adequacy would, in turn, require a separate additional analysis (beyond the scope of the current project).

Please see Appendix I: Reserve dimensioning and international experiences for more information.

Reserve Margin scenario

The Reserve Margin scenario represents the Stated Policies scenario with an addition of a requirement that the installed 'firm' capacity[3] to be exactly the same capacity as the one in the PDP 7 scenario. The total generation capacity developments across the PDP 7, Stated Policies and Reserve Margin scenarios towards 2030 are presented in Figure 16.

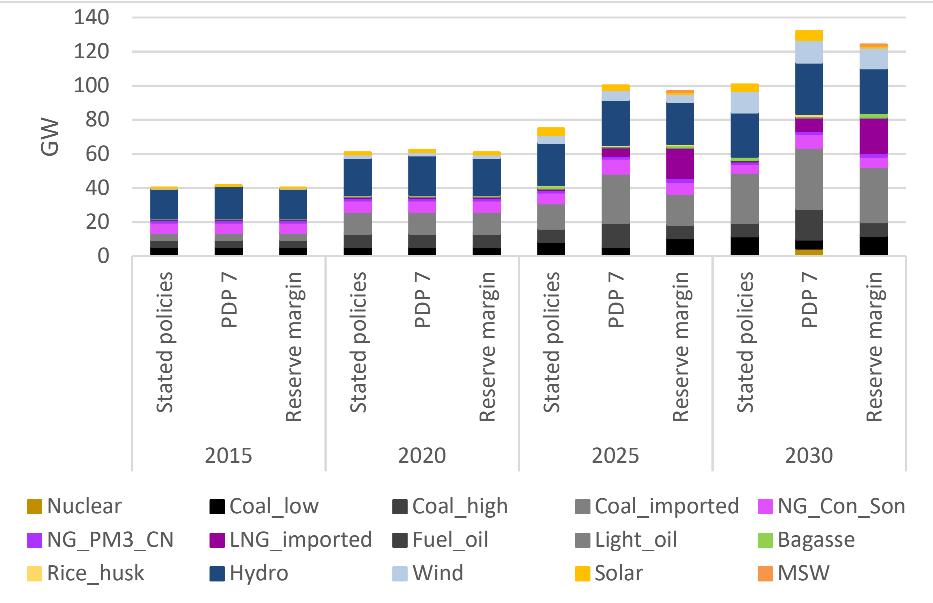


Figure 16: Total generation capacity in the Stated Policies scenario, the PDP 7 scenario and the Reserve Margin scenario (until 2030) (see Appendix IIc for detailed results)

As the results indicate, PDP 7 features much higher total installed generation capacity than the Stated Policies scenario (with identical underlying electricity demand projections), suggesting a significant provision for reserve margin. The Reserve Margin scenario, on the other hand, whilst having the same 'firm

[3] Nuclear, coal, natural gas, fuel oil, light oil, bagasse, rice husk, reservoir hydro, MSW

capacity[4]' as PDP 7, represents a considerably different fuel mix. Reserve Margin in 2030 has less coal-fired capacity than PDP 7 and no nuclear, while featuring higher gas-fired capacity. This outcome is intuitive given that the gas-fired capacity investment costs are significantly lower than those of coal and nuclear, and, provided relatively low full-load hours of operation for the envisioned reserve margin capacity, make for the least-cost solution.

Figure 17 presents the power generation in the three scenarios. As can be seen in the graph, all scenarios meet the power demand, and the generation mix is similar across the scenarios. The results indicate, however, significantly lower operational full-load hours for imported coal-fired generation plants in the PDP 7 scenario compared to the Reserve Margin and Stated Policies scenarios.

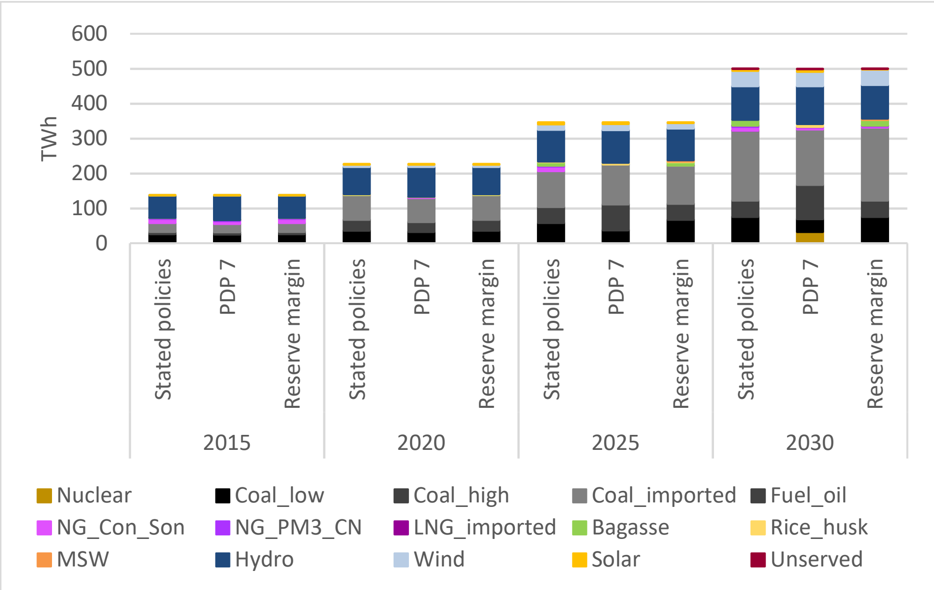


Figure 17: Generation in the Stated policies scenario, the PDP 7 scenario and the reserve margin scenario (until 2030).

Figure 18 presents the total annualized system costs of the Stated Policies and Reserve Margin scenarios, respectively. The cost difference indicates the additional cost required for the provision of the 'firm' capacity reserve margin level consisted with the level in PDP 7 (predominantly based on the addition of gas-fired capacity).

[4] The slight difference in the graph is due to 'hydro' comprising of both reservoir hydro ('firm' capacity) and small run-of-river hydro ('non-firm' capacity) in the representation in the chart. The total 'firm' capacity levels in PDP 7 and Reserve Margin scenarios are identical, however.

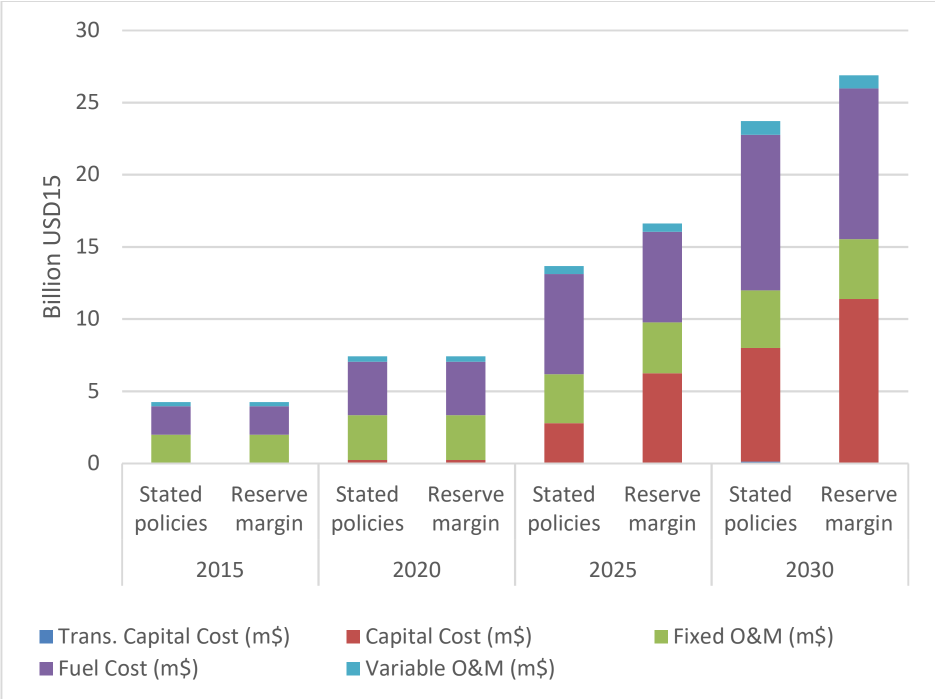


Figure 18: Total system costs per annum (capital costs for generation and transmission are annualized) across scenarios, Balmorel modelling results: Stated Policies scenario and the Reserve Margin scenario (until 2030)

It should though be noted that the expected cost difference between the Stated Policies scenario and the PDP 7 scenario would be higher given the more expensive capital costs of coal-fired power plants compared to gas-fired capacity.

All scenarios

Figure 19 presents the total generation capacity across scenarios. Absence of environmental policies (Unrestricted) results in very limited investment in renewable energy, combined with the highest share of coal-fired power capacity (based on imported coal). However, towards 2030 ca 2.7 GW of wind power capacity investment takes place in the Unrestricted scenario (1.9 GW thereof in the high-wind resource area in the Central region), indicating that the projected RE technology improvements and continued cost reductions would make the best wind resource sites in Vietnam cost-competitive with conventional power generation sources. Towards 2050, cumulative investment capacity of wind and solar PV reach 30 GW and 25 GW, respectively in the Unrestricted scenario, on purely cost-competitive basis.

CO2 Cap, whilst achieving the same CO2 emissions as Stated Policies, results in slightly lower coal-fired capacity investments (instead investing in more gas-fired capacity, which is less carbon-intensive). The impact of CO2 pricing can be observed in the CO2 Price scenario, whereby relatively low CO2 price level in the long term (20 USD/ton) yields similar effect as the ambitious RE requirements (in line with the RE Strategy) mandated in the Stated Policies scenario. A significantly higher CO2 price level (CO2 Price High scenario), in turn, results in much less carbon-intensive power system, wherein investments in coal-fired capacity are minimal, and instead investments in other zero-carbon technologies take place (nuclear, coal CCS, MSW). Similar developments are observed in the No Coal scenario, with the notable difference of significant natural gas-fired generation capacity being added.

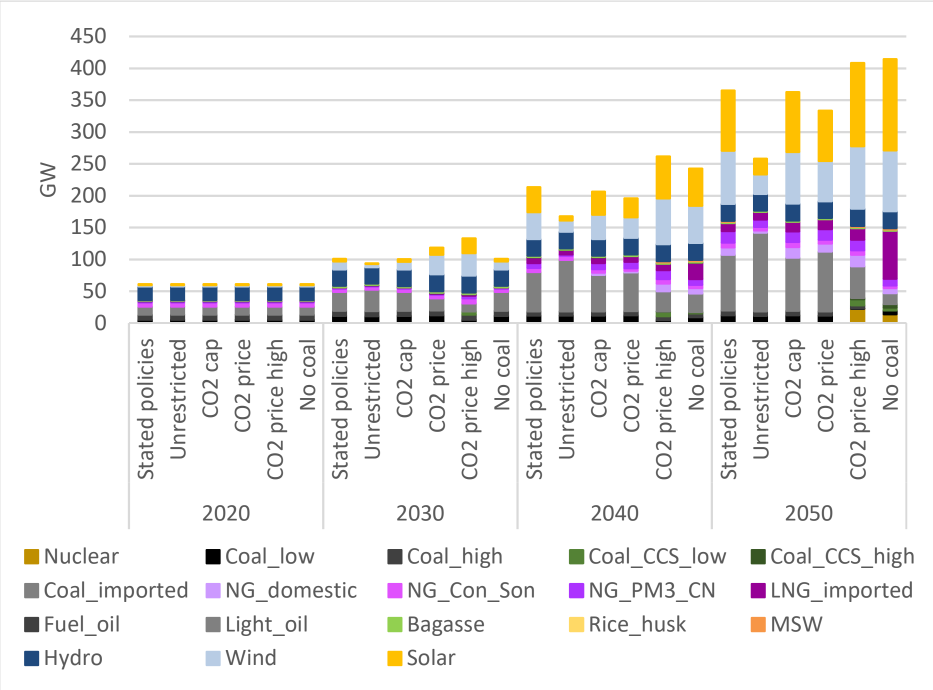


Figure 19: Total generation capacity across scenarios (see Appendix IId for detailed results)

Figure 20 illustrates the model-based power generation results across scenarios. The impact of full-load hours of generation is evident, whereby the renewable energy sources (most notably wind and solar) are less dominant in the generation landscape compared to the capacity mix; whilst the opposite is true for the traditionally baseload generation technologies (most notably coal and nuclear).

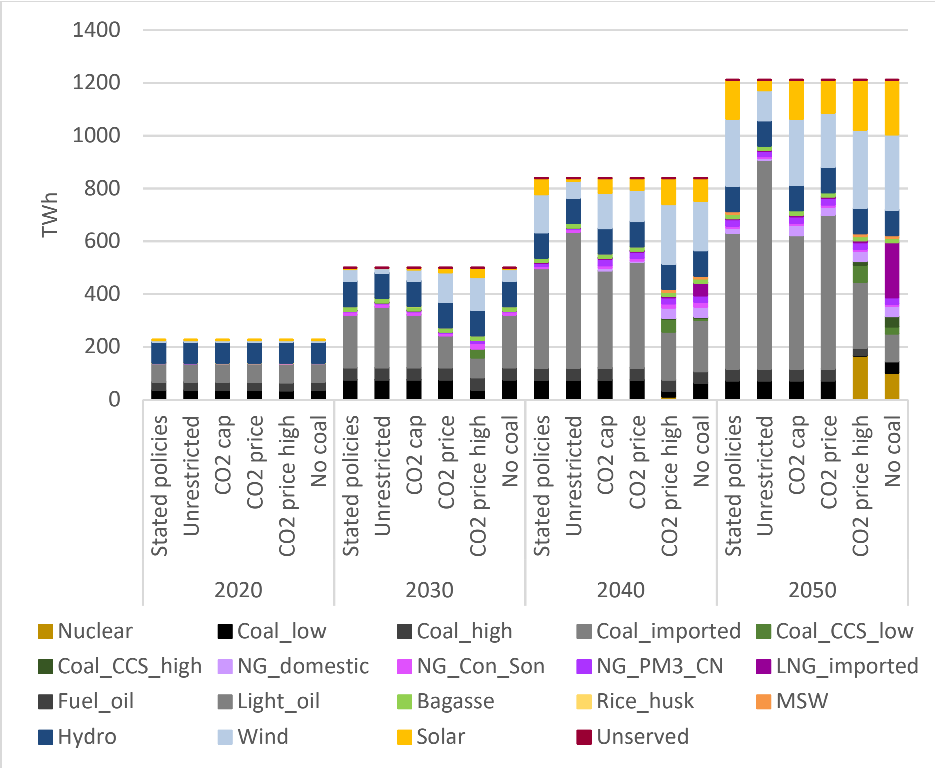


Figure 20: Power generation across scenarios, Balmorel modelling results

Figure 21 presents the RE (including large hydro) generation shares across scenarios, benchmarked against the targets mandated in the RE Strategy (the red line in the graph). Stated Policies, as expected, meets the RE targets exactly over time. Unrestricted, in the absence of any environmental policies, fails to meet the RE Strategy goals beyond 2020, and the discrepancy keeps increasing throughout the projection period. CO2 Price and CO2 Cap both result in comparable RE shares to those attained in Stated Policies in the long term. CO2 Price High and No Coal, in turn, result in the highest shares of RE generation in the long term, significantly exceeding the targets set by the RE Strategy.

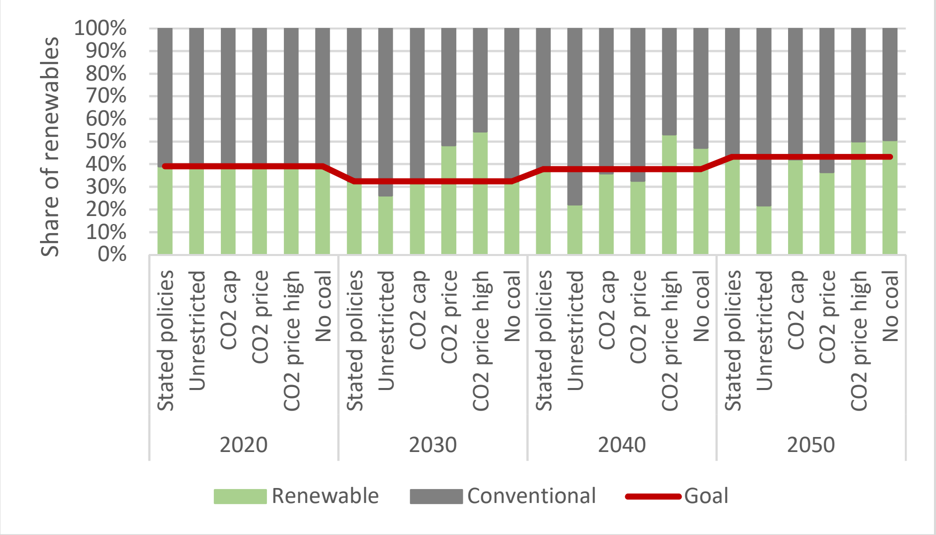


Figure 21: Renewable shares (including large hydro) across scenarios. The Goal represents the targets set by the RE Strategy

Figure 22 paints a similar picture, whereby Unrestricted results in the highest CO2 emissions, significantly exceeding the levels of Stated Policies (and CO2 Cap and CO2 Price), while CO2 Price High and No Coal scenarios result in the most significant CO2 emission reductions in the long term, respectively.

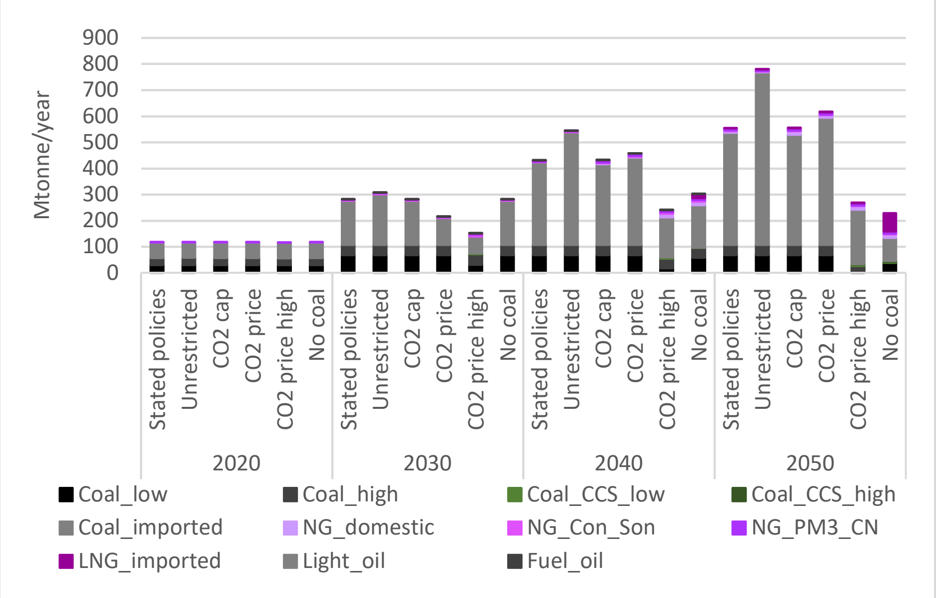


Figure 22: CO_2 emissions across scenarios, Balmorel modelling results

Figure 23 illustrates the role of transmission in RE integration. The scenarios featuring the least RE capacity investments (Unrestricted) result in the lowest corresponding transmission capacity investments. The scenarios with the highest RE investments (both CO2 Price scenarios in 2030, and CO2 Price High and No Coal scenarios 2040 onwards) exhibit the highest transmission capacity investments, respectively.

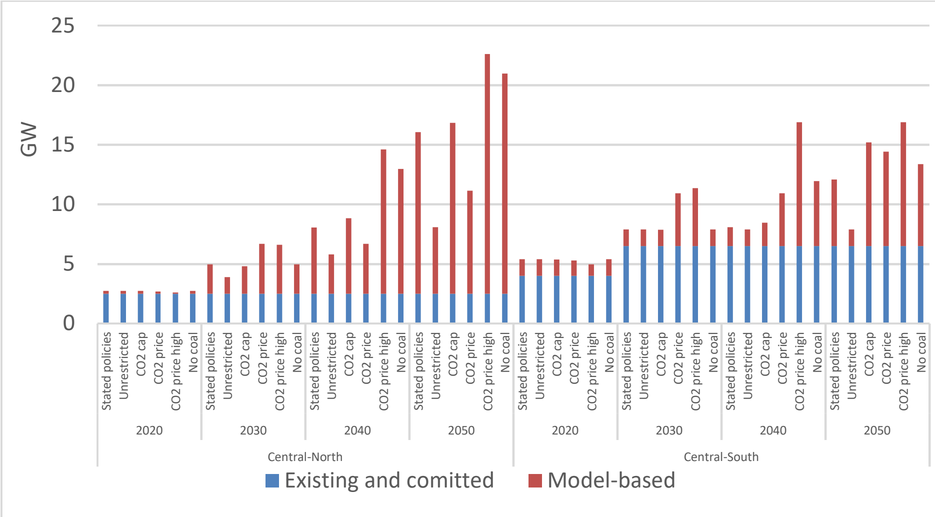


Figure 23: Total transmission capacity across scenarios (see Appendix IIIa for detailed results)

Finally, Figure 24 provides an overview of the total system costs (annualized) across the scenarios (please see description of annualised cost concept in Box 1). Interestingly, the total system cost differences are relatively minor across a number of scenarios. E.g. in 2040, the difference between Unrestricted and Stated Policies is ca 2 bn USD, or a 4% increase compared to the total costs of Unrestricted. In 2050, the corresponding values are 4.9 bn USD or 5.6% increase in costs. These can be interpreted as the additional (annualized) system costs for the implementation of the RE Strategy. The relatively little additional cost can be explained by the fact that while Unrestricted results in lower annualized generation capacity investment costs (Capital Cost) compared to Stated Policies, the latter realizes significant fuel expenditure savings (the higher-CapEx renewables, e.g. wind and solar PV, have no fuel costs).

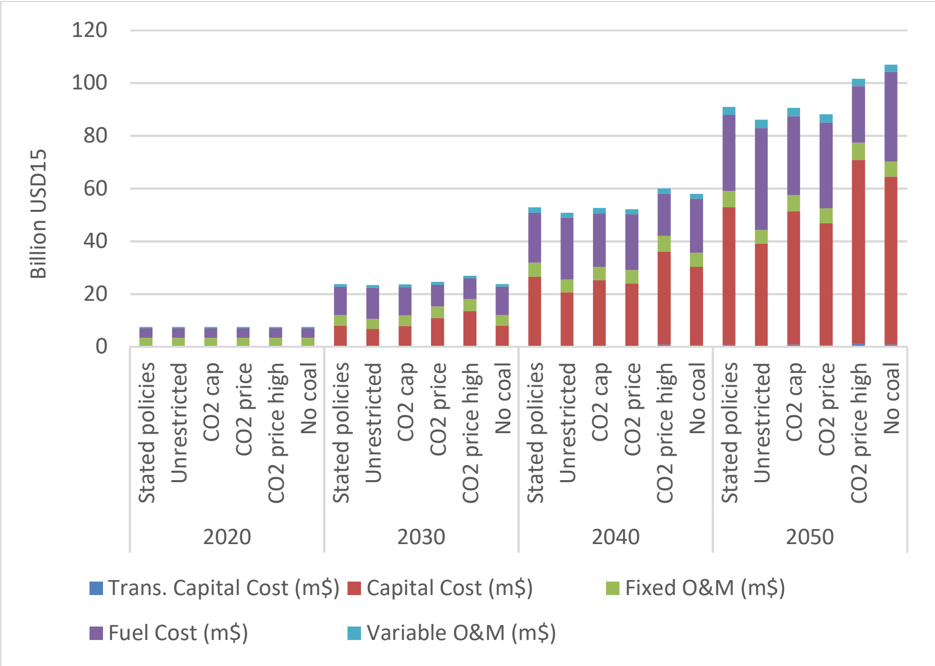


Figure 24: Total system costs per annum (capital costs for generation and transmission are annualized) across scenarios, Balmorel modelling results (see Appendix Iva for detailed results)

Box 1: Annualised costs

Annualised costs

The annualised costs convert the capital expenditure of the project into annual equivalents. This is achieved by converting capital expenditure into annuities, taking into account the interest rate and the economic horizon of the project.

In the present study, interest rate of 10% and economic horizon of 20 years are assumed. This corresponds to an annuity factor of 0.1175.

For example, for a renewable energy technology with an investment cost of US 1.5 M USD per MW, the annualised investment cost will be 11.75% of the initial investment cost, or 0.17625 M USD per MW. For an investment made in e.g. 2020, the annualised capital cost payments would continue throughout the economic horizon, i.e. every year until 2040. The same principle applies to investments made in transmission capacity.

CO2 Cap and CO2 Price appear to have very comparable total system cost levels to that of Stated Policies. It should though be noted that CO2 Cap consistently exhibits slightly lower total system costs than Stated Policies (0.38 bn

USD in 2050), even though both scenarios achieve identical CO2 emission levels. CO2 Price High and No Coal, in turn, are characterized by the highest total system costs – whilst also having realized the lowest CO2 emission levels.

Figure 25 provides an example of the resulting costs per MWh of power generated (total annualized system costs divided by the annual power production) for simulated year 2050, and differences across the scenarios. As expected, Unrestricted produces the lowest cost per MWh. Stated Policies and CO2 Price scenarios are very close, additional cost only comprising 4.9 and 2.1 USD/MWh, respectively. Imposition of a higher CO2 price (CO2 Price High scenario) and new coal build (No Coal) result in higher power generation costs, exceeding the Unrestricted by 16 and 21 USD/MWh, respectively.

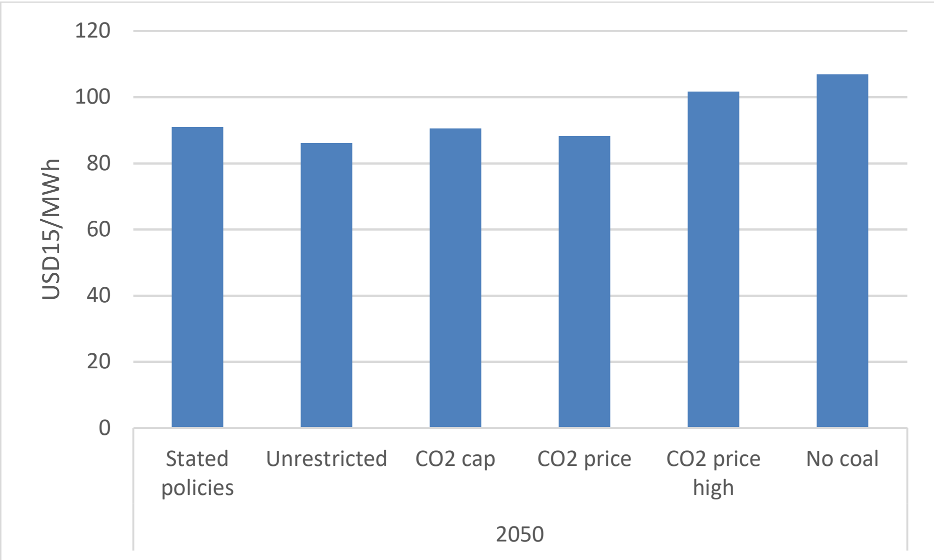


Figure 25: Cost of generation across scenarios, total system costs per annum divided by total generation in 2050, Balmorel modelling results

Figure 26 presents the volumes (in energy terms, in PJ) of coal and natural gas (LNG) imports across the scenarios. The results clearly indicate that absence of environmental policies (Unrestricted) significantly increases the reliance on imported fuels. The most restrictive policy alternative (CO2 Price High and No Coal), in turn, result in the lowest volumes of imported fossil fuels required, due to largest shares of the power demand being covered by domestic renewable resources.

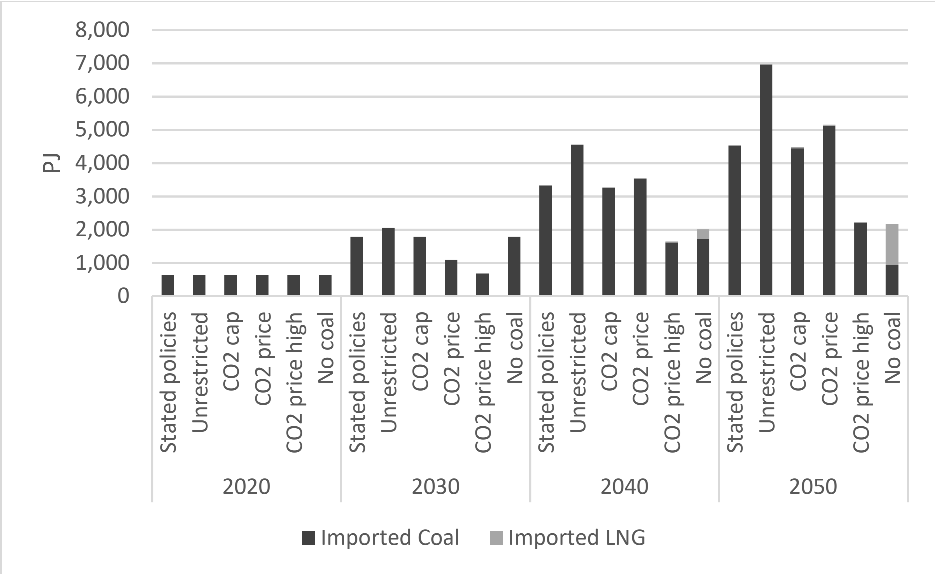


Figure 26: Imported coal and LNG across scenarios, Balmorel modelling results (see Appendix Va for detailed results)

Figure 27 provides an overview of the development in the full-load hours of coal-fired generation across the scenarios over time. In all of the scenarios except Unrestricted (where the RE penetration rate is low), the results illustrate the impact of increasing RE generation entering the system and thereby reducing the utilisation of the conventional coal-fired generation.

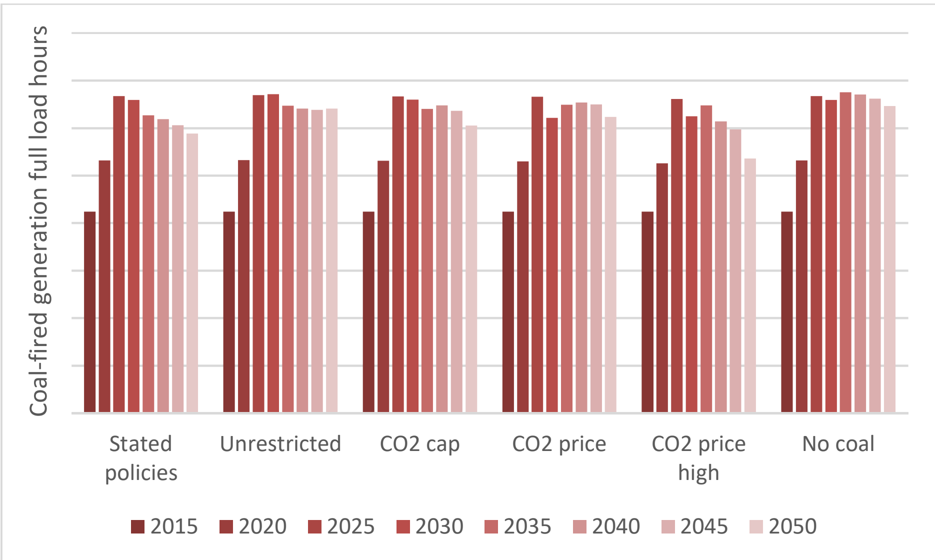


Figure 27: Full load hours for coal-fired generation across scenarios, Balmorel modelling results

Integration of renewables and dispatch

Figure 28 provides an hourly dispatch example for week 40 simulated in the Central region in year 2050 - with unit commitment restrictions activated. The simulation illustrates in an example of a specific week how wind and solar generation is balanced by hydro production and gas-fired generation – at very high RE generation penetration rates.

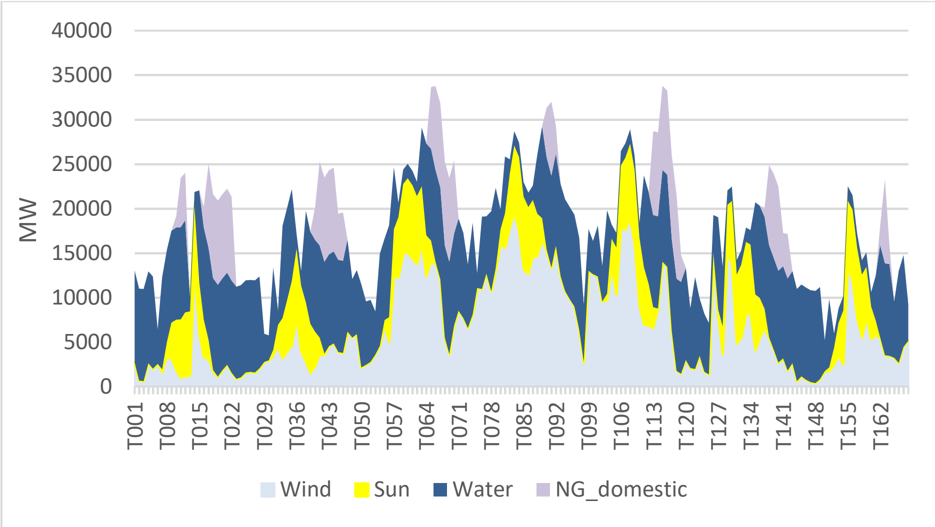


Figure 28: Example of hourly dispatch with unit commitment activated. Balmorel modelling results for Stated Policies scenario in Central region, week 40, year 2050

Figure 29 summarizes the curtailment rates of wind and solar power in the hourly dispatch simulation version of the Stated Policies scenario (with unit commitment activated). The results indicate that curtailment is negligible until 2030 (and until 2040 for solar PV), despite the high total installed capacity levels in both generation technologies. The curtailment rates increase for wind power towards 2040 and 2050, reaching 4% and 8%, respectively, whereas the curtailment rate of solar PV generation stays at ca 3% in 2050.

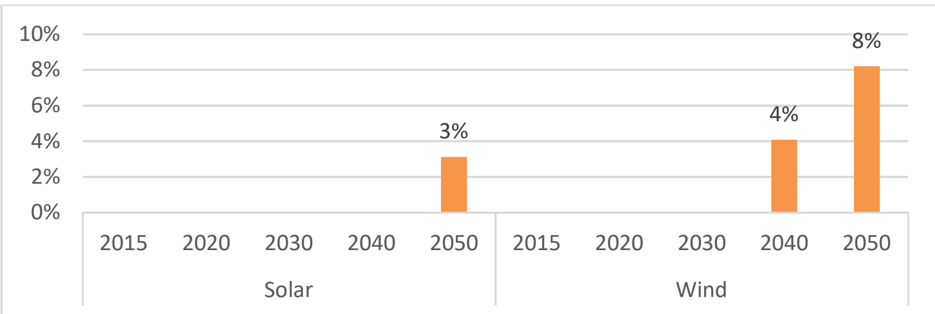


Figure 29: Wind and solar PV curtailment rates in the hourly dispatch simulation of the Stated Policies scenario with unit commitment

It should be noted that additional measures for RE integration could be undertaken, in addition to the ones employed in the model. E.g. demand response, electric storage technologies as well as increased interconnectivity and export to neighbouring countries could additionally improve the RE integration and thereby reduce the potential curtailment rates.

International experience[5]

Power system flexibility, i.e. the extent to which 'a power system can adapt the patterns of electricity generation and consumption in order to maintain the balance between supply and demand in a cost-effective manner', can be provided by a number of sources. Hydroelectric power plants and gas plants (which are able to ramp output up and down very quickly), storage and demand-side management and response can all contribute to efficient integration of variable RES generation. Regional and international connections can also provide flexibility by smoothing variable generation and linking distant flexible resources together (IEA, 2016).

Historically, there have been concerns on the part of power system operators and participants regarding the 'critical level' of RES generation share. In Germany in 1993 and Ireland in 2003 (where the current variable RES generation shares exceed 20% and 23%, respectively), the 'maximum' and 'critical' shares were deemed to be at 4% and 2%, respectively. The initial concern towards variable RES generally can be associated with the notion of load not being controllable, hence fully controllable generation must be used to operate the system (and since variable RES are intermittent, they cannot be relied upon). However, given that the system operation already deals with variable and only partially predictable load, the same resources that balance load can also be utilised to integrate variable RES generation (IEA, 2016).

International experience suggests addressing the following issues at an early stage of RES generation integration (IEA, 2016):

- "Ensure that the technical standards (known as grid codes or connection standards) for variable RE power plants are up to date and already contain appropriate provision for technical capabilities that can become critical once variable RE comprises a larger portion of the generation fleet;

[5] Based on 'Next Generation Wind and Solar Power - from Cost to Value' (IEA, 2016). Please see the publication for more information

- Forecast production from variable RE using centralised forecasts and effectively use forecasts when planning the operation of other power plants and electricity flows on the grid;
- Ensure that system operators have access to real-time production data and that a sufficient share of variable RE generators can be controlled remotely by them (priority should be given to largescale variable RE plants). This may require the installation of additional smart-grid hardware;
- Avoid unintended local concentrations of variable RE power plants, both in one region of a country as well as in certain parts of the grid within a given region, to avoid technical challenges in these regions".

Power systems with variable RES generation shares above 10% are increasingly common (over 50% in Denmark, 23% in Ireland, and 21% in the Iberian Peninsula), and these levels have been achieved predominantly by enhanced *operation* of the existing power system assets rather than significant additional investments. However, beyond a certain point, additional measures are needed, including investment in additional flexibility resources. Policy, market and regulatory frameworks have a critical impact on the success of RE integration. In addition, flexibility can also be provided by sources outside of the electricity sector e.g. electrification of transportation whereby electric vehicles can provide storage. The role of operational procedures should also be considered, e.g. by expanding the balancing area reduces the aggregate variability and consecutively the need for active balancing (IEA, 2016).

A common and important issue in RE integration is that of making the dispatchable fleet, especially coal-fired power plants, more flexible. Power plant flexibility is expressed in a number of capabilities: starting up production at short notice; operating at a wide range of different generation levels; and quickly moving between different generation levels (IEA, 2016).

The adaptations made in the power systems with the highest variable RE generation shares (Denmark, Germany and Spain) have largely been improvements in the way each system is operated, including more advanced market designs allowing for trading very close to real time, upgrades to thermal power plants to cope with more rapid swings in demand, and active use of interconnections where available. International experience also suggests that a *comprehensive and systemic* approach of this kind is the most cost-efficient and secure answer to system integration challenges, as opposed to viewing the role of variable RE in the power system in isolation. The latter perspective likens the variable RES as to 'traditional' generation sources by e.g. favouring addition of storage or dedicated power plants to balance RE generation. IEA analysis has demonstrated that the isolated approach results in 'significantly higher costs than a more system-wide strategy' (IEA, 2016).

The case of Denmark[6]

System operation and the power market represent the two central pillars on which the successful Danish integration of wind power has been built (Danish Energy Agency, 2015):

- System operation with accurate wind forecasts and adequate reserve capacity for periods with little wind and a demand side that automatically adapts in situations where there is too little or excess production from wind power;
- A well-functioning power market – in which players trade themselves into balance, i.e. supply equals projected demand (intra-day market) and a market for balancing power (the regulating power market) operated by the TSO.

The increased amount of wind power has displaced some of the large central power stations and thus the system services these systems have traditionally delivered. It therefore became necessary to make increased requirements regarding the connection of wind turbines and their system characteristics (such as low voltage fault ride-through capability, power and frequency control), which had previously been delivered from thermal power plants. Technical regulation must be in place in appropriate detail to ensure the physical grid functioning and system security. Grid codes could be designed to require wind turbines to e.g. (Danish Energy Agency, 2015):

- Disconnect during abnormal voltage and frequency events;
- Remain connected to the grid in case of fault;
- Be controllable remotely;
- Curtail if necessary.

A strong transmission and distribution grid with strong interconnections to neighbouring power markets is an important element in large scale wind deployment. In the Danish case the interconnectors to Norway and Sweden are especially important as the interconnectors to these two countries make it possible to balance wind power and hydro power. When Danish wind turbines generate more power than required, surplus power is often transmitted to Norway or Sweden, which reduces the draw on the water reservoirs. When

[6] Please see 'Energy Policy Toolkit on System Integration of Wind Power - Experiences from Denmark' (Danish Energy Agency, 2015) for more information

the wind calms down, the hydro power stations increase production, transmitting power to Denmark. Robust interconnections and an efficient market and cooperation between the Scandinavian TSOs have proved to be important in importing and exporting environmentally friendly power and in increasing the share of wind power in Denmark (Danish Energy Agency, 2015).

Accurate wind forecasting is becoming increasingly important as the share of wind power generation increases. One meter per second deviation in wind speed, and the corresponding unexpected sudden increase or decrease in wind power generation, may be quite noticeable as well as costly in the system. However, today's wind forecasts are so advanced that it is possible to estimate production with high certainty up to 36 hours prior to the actual production hour – although quite large prognosis errors can still occasionally occur (requiring balancing up to and within the hour of operation). Another important aspect is how the prognoses are used in the system operation. Every six hours the prognoses are updated due to new weather forecasts, and as the hour of operation approaches, the prognoses are also updated with real-time information (Danish Energy Agency, 2015).

Box 2 summarizes the key lessons learnt towards successful integration of large shares of variable RE generation in Denmark.

Box 2: International experience in RE integration: lessons learnt from Denmark

International experience in RE integration: lessons learnt from Denmark

- "Ambitious targets, long-term planning and strong and stable political framework conditions can pave the way for significant private investments by creating a positive and secure long-term investment climate
- Strong and independent TSOs are vital to a successful system integration of wind power
- A well-functioning market such as the Nordic power exchange Nord Pool ensures a transparent and cost-efficient transfer of power from areas with high production and low demand to areas with low production and high demand. This provides power producers with a clear incentive to adapt production to the market signals
- Unbundling of generation and transmission creates a level playing field for all power producers
- Interconnectors to neighbouring countries or to a wider grid area that allow surplus energy to be easily transferred from one area to another help increase the security of supply
- Technical demands and specifications such as grid codes for wind power can ease the integration of wind power into the wider grid and power system
- Advanced forecasting can help the TSOs in the operation of the wider power system including possible activation of regulating power generators" (Danish Energy Agency, 2015)

Sensitivity analyses

Additional scenarios have been created to illustrate the 'alternative futures' under different materialization pathways of some of the key external drivers, namely the power demand trajectories and global fuel and technology costs.

Low RE Costs

A scenario with lower RE technology investment costs is created to investigate the sensitivity of the optimal power system setup to variation in the RE cost development. This is particularly relevant in light of the very steep and game-changing RE cost reductions having taken place in the recent years (which were broadly not anticipated), combined with a number of competitive RE auctions having resulted in further significant reductions in the expected costs of RE projects.

The lower investment costs for solar PV are starting out based on the estimated investment costs underlying the most recent winning solar PV competitive auction bids globally[7] (Ea Energy Analyses, 2017), and applied learning curve thereafter in line with the assumptions made in Stated Policies. For wind power, the investment cost projections are derived from the Technology Catalogue of the DEA (Danish Energy Agency, 2016), reflecting the expected feasible dynamics in mature market conditions for wind power technology. The investment cost assumptions of the Low RE Costs scenario vis-à-vis the Stated Policies scenario are shown in Figure 30.

	2020	2025	2030	2040	2050
Stated Policies Wind	1,971	1,813	1,656	1,555	1,454
Low RE Costs - Wind	1,189	1,141	1,094	1,050	1,006

	2020	2025	2030	2040	2050
Stated Policies Large scale	1,119	1,022	925	839	753
Stated Policies Rooftop	1,344	1,239	1,134	1,029	945
Low RE Costs - Large scale	611	553	495	438	382
Low RE Costs - Rooftop	734	670	606	538	479

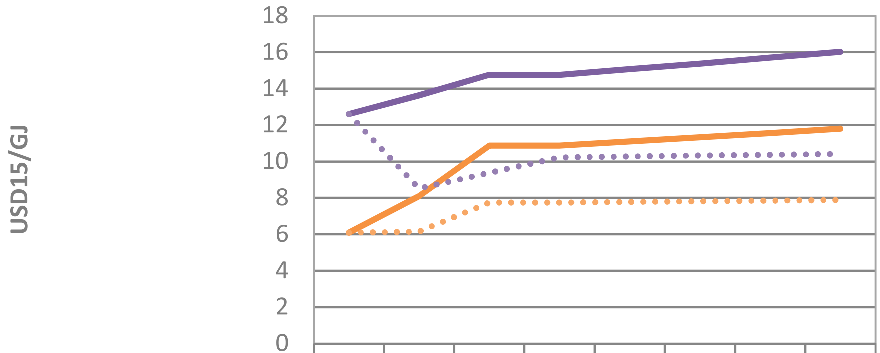
Figure 30: Investment cost assumptions in wind and solar PV projects in the Stated Policies and Low RE Costs scenarios, respectively (USD15/kW)

Low NG Price

International fuel prices – and future projections thereof - is another critical consideration and driver in power system planning. In the present study, the

[7] Mexico, Peru, Dubai, Europe

Low NG Price scenario will investigate the sensitivity of the optimal power system setup to variation in natural gas price development. Natural gas price projections in the Low NG Price scenario follow the (IEA, 2016) - 450 PPM scenario (LNG imports - Japan), as illustrated in Figure 31.



	2015	2020	2025	2030	2035	2040	2045	2050
Stated pol. - Domestic NG	6.09	8.10	10.87	10.87	11.10	11.33	11.57	11.80
Stated pol. - Imported LNG	12.60	13.64	14.76	14.76	15.07	15.38	15.70	16.02
Low NG - Domestic NG	6.09	6.15	7.74	7.74	7.79	7.81	7.85	7.89
Low NG - Imported LNG	12.60	8.52	9.38	10.23	10.28	10.32	10.37	10.42

Figure 31: Natural gas price future projections in the Stated Policies and Low NG Price scenarios, respectively (USD 2015/GJ)

High and Low Demand

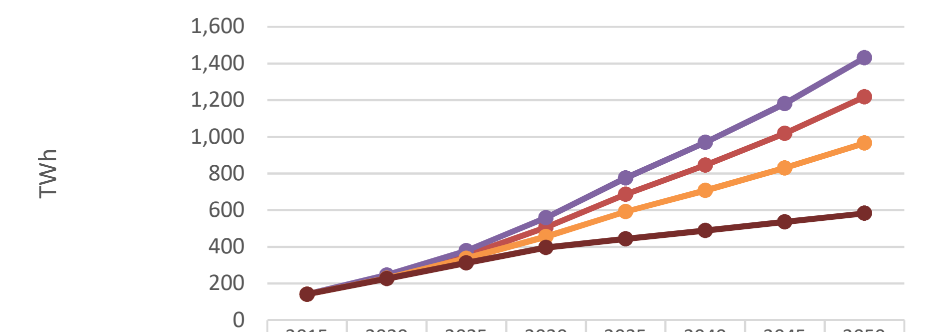
Electricity demand projections is one of the most important inputs in power system planning. In the current study, the impact of both higher and lower power demand development in the future will be investigated in High Demand and Low Demand scenarios, respectively. In addition, an ambitious Very Low Demand scenario is explored. Both the high and low demand projection variations are based on the cases projected in PDP 7 revised towards 2030, and extrapolated towards 2050 (IE, Institute of Energy).

Very Low Demand

The Very Low Demand scenario power demand projection is based on the Sustainable Energy Scenario (SES) prepared within a study commissioned by the WWF (IES and MKE, 2016). The power demand forecast underlying the SES envisions a transition of electricity demand in Vietnam towards the best practice benchmarks of other developed countries in terms of, among other things, energy efficiency (please see 'Alternatives for Power Generation in the Greater Mekong Sub-Region - Volume 7: GMS Power Sector Vision Modelling Assumptions Summary' for full context and assumptions underlying the power demand projection). In terms of industrial electricity intensity, Vietnam is deemed to have a very high kWh/USD. In the SES power demand forecast, the

Vietnamese industrial electricity intensity rate is assumed to trend back towards Korea's 0.6 level by 2035 (citing similar heavy industry based economies), and continue the trajectory to 2050 (IES and MKE, 2016).

The demand projections implemented in the High Demand, Low Demand and Very Low Demand scenarios are presented in Figure 32.



	2015	2020	2025	2030	2035	2040	2045	2050
Stated Policies	142	234	352	506	687	846	1,019	1,218
High demand	142	245	379	559	775	969	1,182	1,430
Low demand	142	228	337	456	592	708	829	965
Very low demand	142	227	312	396	443	489	536	582

Figure 32: Power demand projections in Stated Policies, High Demand, Low Demand and Very Low Demand scenarios, respectively (TWh)

Demand, fuel price and RE cost sensitivity results

Figure 33 presents the total optimal generation capacity in response to the changing framework conditions as prescribed by the sensitivity analysis scenarios. First and foremost, the results illustrate the extremely high impact of the demand projections on the eventual optimal power system setup and size. Both Stated Policies, and all of the demand projection variation scenarios (High, Low, Very Low) meet the required RE Strategy targets, but achieve this goal with very different total RE resources required (from 48 GW of wind and solar PV in Very Low Demand scenario by 2050 to 235 GW in High Demand scenario, respectively). The total capacity installed also varies substantially in response to the demand development planning assumptions applied.

Fuel price assumptions are another powerful driver of the optimal power system setup. Provided lower natural gas prices, more gas-fired capacity and less coal-fired capacity (a decrease of 12.8 GW of imported coal-fired capacity compared to Stated Policies in 2050) would be the least-cost solution system-wide.

Similarly, strong continuation of cost reductions in RE technologies result in higher RE installed capacities (solar PV making up a much larger share thereof), whilst reducing coal-fired generation capacity in favour of gas-fired capacity.

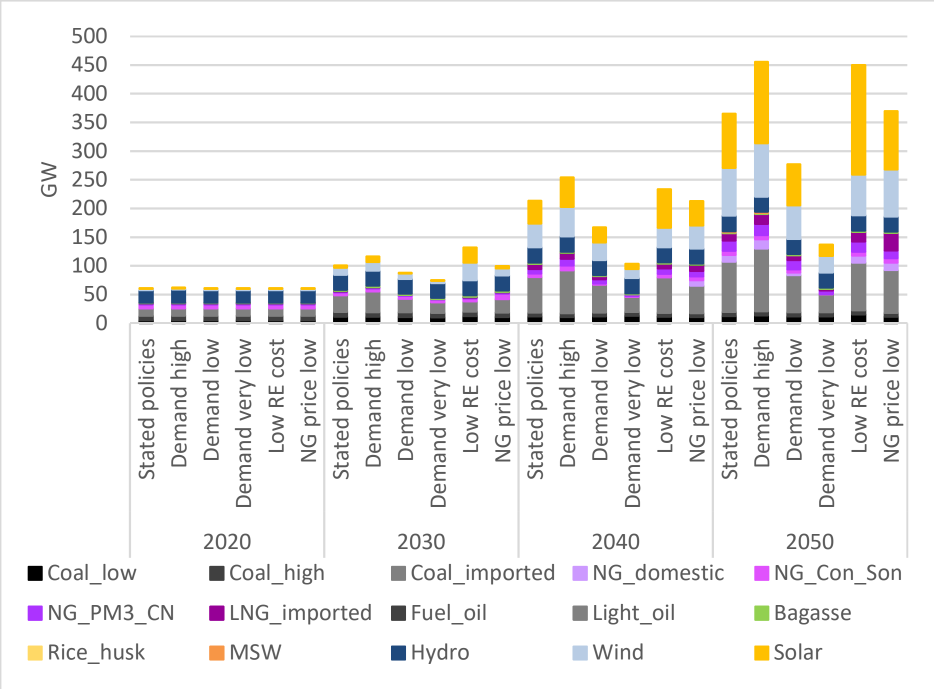


Figure 33: Total generation capacity across the sensitivity analysis scenarios (see Appendix IIe for detailed results)

Figure 34 presents the RE (including large hydro) generation shares across scenarios, benchmarked against the targets mandated in the RE Strategy (the red line in the graph). All scenarios have the same RE generation share requirements implemented as for Stated Policies, yet some of the scenarios in fact exceed them. Low RE costs make solar PV in particular (but also wind) more cost-competitive relative to the other generation technologies, resulting in some RE capacity additions taking place purely on competitive basis (e.g. in 2030 where the RE target is exceeded for the Low RE Cost scenario).

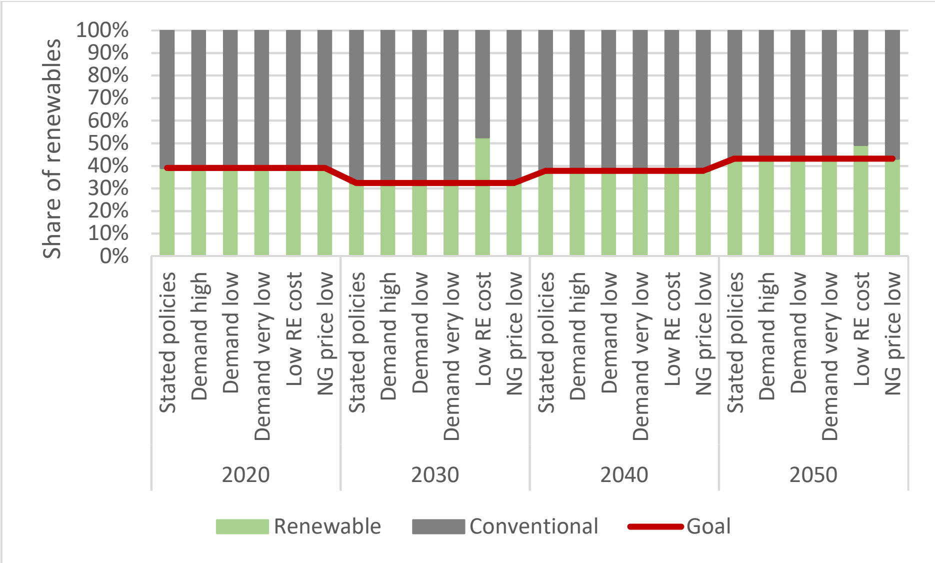


Figure 34: Renewable shares (including large hydro) across scenarios. The Goal represents the targets set by the RE Strategy

Figure 35 presents the CO2 emission levels of the different sensitivity analysis scenarios. As expected, the demand projections have significant impact on the CO2 emission levels, thereby illustrating e.g. the potential environmental benefits of energy efficiency improvement measures. The lower RE costs make wind and solar PV more cost-competitive, thereby substituting some of the more CO2-intensive generation technologies. Finally, materialization of a lower natural gas price development projection also tilts the optimal system setup towards the less carbon-intensive natural gas-fired technologies.

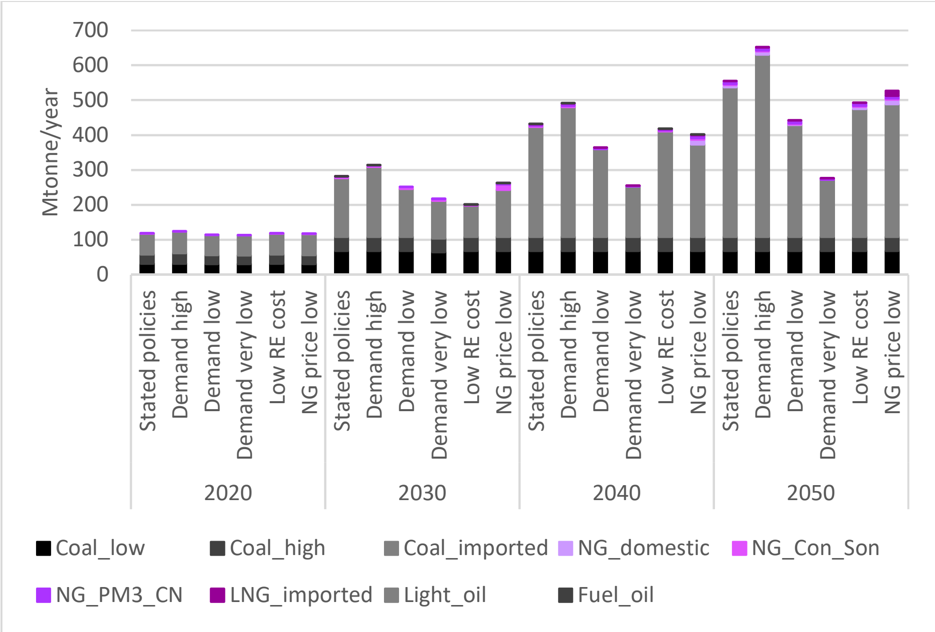


Figure 35: CO_2 emissions across the sensitivity analysis scenarios, Balmorel modelling results

Figure 36 provides an overview of the total system costs (annualized) across the sensitivity analysis scenarios. As expected, the demand projections have direct impact on the total system costs, again emphasizing the importance of both the planning assumption selection, as well as the benefit of improving energy efficiency practices. Also, intuitively, lower natural gas price and lower RE investment costs both result in lower total system costs – and it should be noted that in both cases the system cost reductions are accompanied with reduction in CO2 emission levels compared to the Stated Policies scenario.

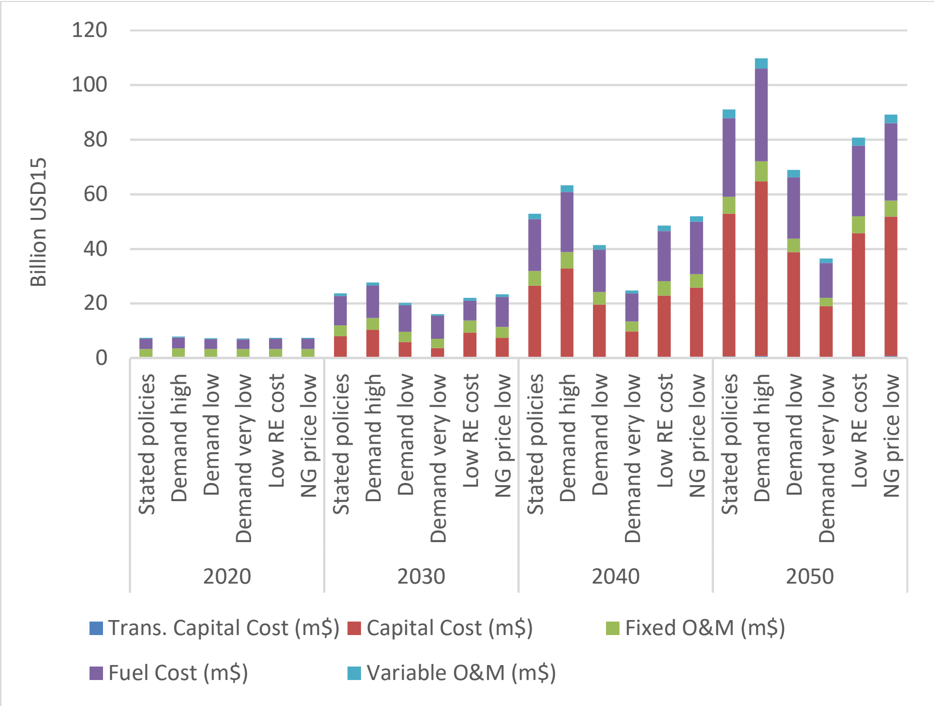


Figure 36: Total system costs per annum (capital costs for generation and transmission are annualized) across the sensitivity analysis scenarios, Balmorel modelling results (see Appendix IVb for detailed results)

Figure 37 presents the volumes (in energy terms, in PJ) of coal and natural gas (LNG) imports across the scenarios. Again, higher electricity demand increases the need for imported fossil fuels, while scenarios featuring more domestic renewable resources reduce the reliance on imports.

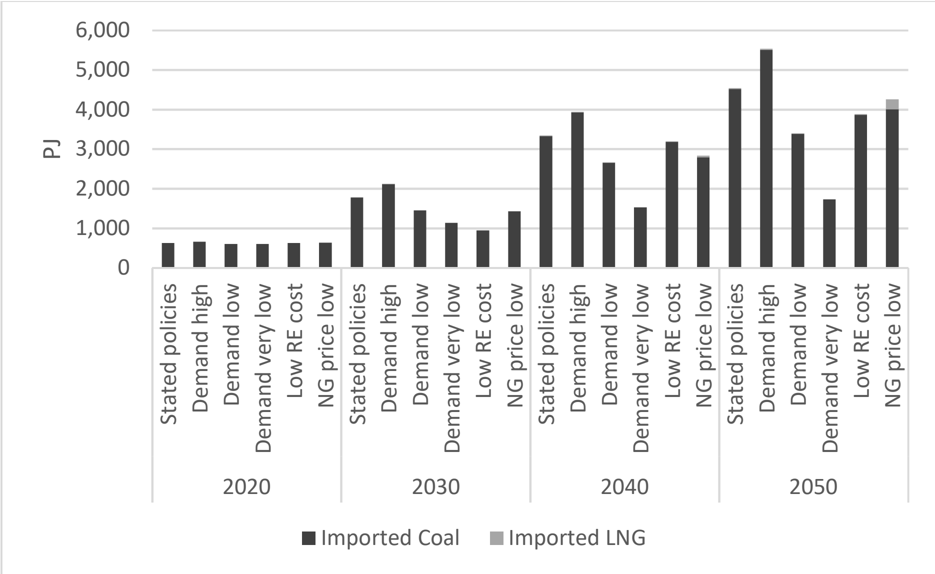


Figure 37: Imported coal and LNG across the sensitivity analysis scenarios, Balmorel modelling results (see Appendix Vb for detailed results)

5 Discussion and conclusion

The development of the Vietnamese electricity system has been studied from the current state and until year 2050. Least-cost model-based investment simulations using the Balmorel model, an open-source modelling framework, which has been populated with detailed data for the current Vietnamese electricity system and the expected future development, have been used to illustrate a number of possible futures. It is well understood that the input data projections towards year 2050 are subject to a high degree of uncertainty. The power system development pathways hereby presented are not to be regarded as forecasts; rather, as illustrations of potential implications of different alternative policy choices, subject to materialization of the underlying set of projections and assumptions.

RE integration

The analysis results indicate that it is possible to operate the Vietnamese electricity system with high levels of variable renewable energy. The dispatchable hydro generation capacity contributes to the system flexibility. The small amount of curtailment (no curtailment for solar PV and 4% curtailment for wind in 2040 in the Stated Policies scenario at 42 GW wind and 39 GW solar capacity in the system) indicates an efficient integration of wind and solar power in the system. Part of the reason for this is that all economic investment in transmission has been included which will contribute to accommodating the variable renewable energy.

Curtailment can be reduced further, e.g. with additional measures that presently have not been included in the analyses, like demand response and interchange with neighbouring countries.

Environmental policy alternatives

In the absence of environmental policies (Unrestricted scenario), the modelling results indicate a highly coal-dominated power system in Vietnam towards 2050, which does not meet the RE Strategy goals and features high levels of CO2 emissions.

The Stated Policies scenario, which features the RE Strategy goals as a requirement, exhibits significant shares of wind and solar PV generation, and delivers CO2 emission reductions, and does so at minor additional system cost. E.g. in 2040, the difference between Unrestricted and Stated Policies is ca 2 bn USD, or a 4% increase compared to the total costs of Unrestricted. In 2050, the corresponding values are 4.9 bn USD or 5.6% increase in costs.

These can be interpreted as the additional (annualized) system costs for the implementation of the RE Strategy. The relatively little additional cost can be explained by the fact that while Unrestricted results in lower annualized generation capacity investment costs (Capital Cost) compared to Stated Policies, the latter realizes significant fuel expenditure savings (the higher-CapEx renewables, e.g. wind and solar PV, have no fuel costs).

CO2 Cap consistently exhibits slightly lower total system costs than Stated Policies (0.38 bn USD in 2050), even though both scenarios achieve identical CO2 emission levels. CO2 Price High and No Coal, in turn, are characterized by the highest total system costs – whilst also having realized the lowest CO2 emission levels.

It is a political decision whether these increases in cost are worth the outcome (e.g. lower emission levels). The analyses indicate how emission reduction can be achieved most efficiently, other things being equal.

Reliance on imported fuels

Absence of environmental policies (Unrestricted scenario) significantly increases the reliance on imported fuels, particularly imported coal. The most restrictive policy alternatives (CO2 Price High and No Coal), in turn, result in the lowest volumes of imported fossil fuels required, due to largest shares of the power demand being covered by domestic renewable resources.

RE resource potential

Land-based wind resource potential estimates have been based on the interim results of the wind resource mapping project supported by the GIZ in collaboration with the Danish Energy Agency, 'Macroeconomic Cost-Benefit Analysis for Renewable Energy Integration' (Ea Energy Analyses and DHI GRAS, 2017). Based on the preliminary results, significant feasible wind power potential is available in Vietnam (27 GW) – and further large potential is unlocked in the long term if siting restrictions on croplands are removed (144 GW).

Competitiveness of RES (wind and solar PV)

The results indicate that already in the medium-term (i.e. towards 2030) significant investments in wind power capacity (exceeding 2.7 GW) could take place in Vietnam on cost-competitive basis, provided the materialization of continued RE technology cost reduction and improvements. The cumulative capacity of cost-competitive investments in wind and solar PV by 2050 in the Unrestricted scenario reaches 30 GW and 25 GW, respectively.

Electricity demand development

Whilst appreciating the high degree of uncertainty associated with making long-term projection of electricity demand, historical international perspective could be applied when evaluating the current power demand projections for Vietnam that are characterised by continuous high growth rates also in the long term. Structural shifts (away from energy-intensive heavy industries and towards more service-based economy) as well as advances in energy efficiency (both in industry and buildings, as well as in household appliances and lighting), among other drivers, have contributed to a disconnect between power demand and GDP growth observed globally, once a certain level of economic development has been achieved. In Vietnamese context, this could warrant (potentially significantly) lower power demand growth rate projections towards 2050.

Sensitivity analyses

Power demand projections

The results indicate extremely high impact of the demand projections on the eventual optimal power system setup and size. Both Stated Policies, and all of the demand projection variation scenarios (High, Low, Very Low) meet the required RE Strategy targets, but achieve this goal with very different total RE resources required (from 48 GW of wind and solar PV in Very Low Demand scenario by 2050 to 235 GW in High Demand scenario, respectively). The total capacity installed also varies substantially in response to the demand development planning assumptions applied. As expected, the demand projections have direct impact on the total system costs as well, again emphasizing the importance of both the planning assumption selection, as well as the potential economic benefit of improving energy efficiency practices.

The demand projections also have significant impact on the resulting CO2 emission levels, thereby illustrating e.g. the potential environmental benefits of energy efficiency improvement measures.

Fuel prices

Fuel price assumptions are another powerful driver of the optimal power system setup. Provided lower natural gas prices, more gas-fired capacity and less coal-fired capacity (a decrease of 12.8 GW of imported coal-fired capacity compared to Stated Policies in 2050) would be the least-cost solution system-wide, whilst maintaining the high shares of wind and solar PV generation. Materialization of a lower natural gas price development projection also results in lower CO2 emissions, due to the natural gas-fired technologies being less carbon-intensive.

RE technology costs

The continuation of cost reductions in RE technologies would result in higher RE installed capacities (solar PV making up a much larger share thereof), whilst reducing coal-fired generation capacity in favour of gas-fired capacity. Low RE costs make solar PV in particular (but also wind) more cost-competitive relative to the other generation technologies, resulting in some RE capacity additions taking place purely on competitive basis (e.g. in 2030 where the RE target is exceeded for the Low RE Cost scenario).

Recommendations for future analyses

The analysis has been carried out using the best available information at the time of writing of this report. A number of additional updates and analysis perspectives would, however, be value adding to consider going forward:

- Refinement of RE resource representation
    - Solar PV resource potential implementation in line with currently on-going World Bank study once it is made public
- Refinement of the power demand projections taking into consideration international trends in electricity intensity as well as the development projections of the respective economic sectors
- Incorporation of energy efficiency in the scenario analyses
    - The current power demand projections assume continued rapid growth towards 2050, which might be significantly underestimating the impact of improved energy efficiency measures in Vietnam
- Incorporation of regional interconnection options in the scenario analyses
    - Regional interconnections and import / export of power is an additional effective measure for improving the integration of large shares of RE generation
- Incorporation of demand response and storage technologies in the scenario analyses
    - Presently only pumped hydro storage is made available as an investment technology
- Exploration of near-shore wind as a technology option for Vietnam
    - Following the very rapid cost reductions observed in offshore wind technology, this could become a competitive (and abundant) domestic renewable energy source option for Vietnam
- Refinement of hydro reservoir power plant representation
    - Incorporate the operational limitations associated with other functions of hydro reservoirs (flood control, irrigation, transport etc.)
    - Incorporation of more Vietnam-specific pumped hydro storage projects as investment options (characteristics, costs, location)
- Closer look into the hourly dispatch of the system, including unit commitment considerations across all scenarios - as well as more detailed representation of transmission capacity (N-1 and other operational aspects)
- Analysis of the reserve margin and more detailed system cost considerations in relation to the projected increasing shares of intermittent RES generation

- Stochastic system adequacy analysis could be a value-adding method to shed light on the system reserve requirements with increasing shares of RE generation in the system

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Appendix I: Reserve dimensioning and international experiences

This section has been based on 'Renewable energy and reliability of electricity supply' by Ea Energy Analyses, EOH Enerweb, DTU and Eskom (2016).

Over and above the capacity to match the peak demand, power systems require additional capacity to deal with failures, unbalances, planned and unplanned events.

The first two types of capacities are called system reserves:

- Capacity to cope with major, sudden failures (N-1) – short term perspective (seconds). Automatic and manual reserves.
- Capacity to cope with unbalances – medium term perspective (minutes to hours). Unbalances can come from demand, outage of traditional generation and transmission lines – or can be unbalances from renewable energy (wind and solar)

Increasing amounts of variable generation has impacted the dimensioning techniques and the approach to reserve dimensioning.

International review of reserve allocation

In literature, the following three international organisations are often referred to in conjunction with reserve levels and level setting:

- National American Electric Reliability Corporation (NERC);
- European Network of Transmission System Operators for Electricity (ENTSO-E);
- Union for the Coordination of Transmission of Electricity (UCTE).

Today UCTE is the region 'Central Europe' in ENTSO-E.

Despite the differences in terminology, the categories for reserve level setting in ENTSO-E maps closely to those used by UCTE. NERC however, treats normal operating reserves (regulating and load following) separate to reserves allocated to contingencies (frequency, spinning, non-spinning and replacement).

Figure 38 shows a mapping between the categories in use by the different organizations.

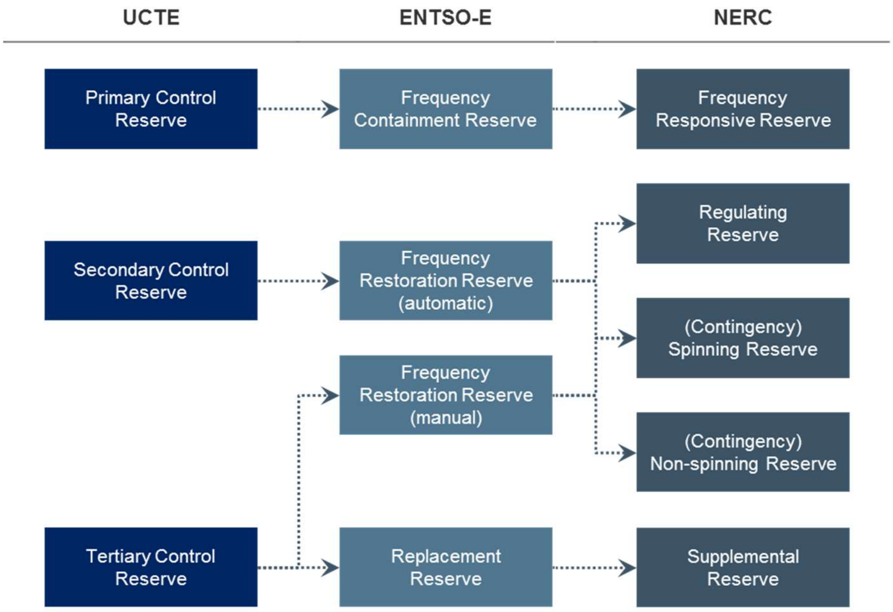

Figure 38: Mapping between UCTE, ENTSO-E and NERC reserve categories

ENTSO-E uses the largest contingency criteria for the dimensioning of reserves:

- Frequency containment reserve: N-1 and N-2 (for the region Central Europe)
- Frequency Restoration Reserves – in conjunction with variation of nett load (see below)
- Replacement reserves – the largest expected loss of power (generation unit, power infeed, DC-link or load) in the control area.

With increasing penetration of variable generation, probabilistic methods based on the variation in nett load (load minus variable generation) were developed and used in the dimensioning of Frequency Restoration Reserves and Replacement Reserves, respectively. The reference incident is often used as a minimum requirement.

Similarly, NERC [5] uses the largest contingency criteria for dimensioning their contingency reserves (spinning and non-spinning). ERCOT [6] (the ISO in Texas), has adopted a probabilistic approach based on variations in nett load, for the dimensioning of the regulating reserves and non-spinning contingency reserves.

Dynamic dimensioning of reserves is a practice employed in, for example, Australia and ERCOT [6][7]. The reserve levels are regularly evaluated and adjusted if necessary, based on performance. ERCOT integrated this approach into their probabilistic assessment.

Integration studies on impact of increased variable generation

Impact on reserve dimensioning

A number of wind integration studies were reviewed [1]-[5] to obtain insights into the impact of increases in variable generation on reserve levels. In the integration studies reviewed, most of the impact on system capacity reserves are on dimensioning of the tertiary reserves, e.g. load following, replacement reserves etc. and not the faster response categories.

Moderate increases are reported in regulating reserves and larger increases in the reserve requirements for load following and replacement. These studies assume that the operating procedures are unchanged when estimating these impacts.

For wind generation, the secondary reserves are impacted modestly and adjustment approaches using geometric addition of wind variability were proposed [2].

The impact on tertiary reserves are due to increase in nett load forecasting errors, which is a function of geographic distribution and forecast horizon, as shown in these figures from [2] and [3]:

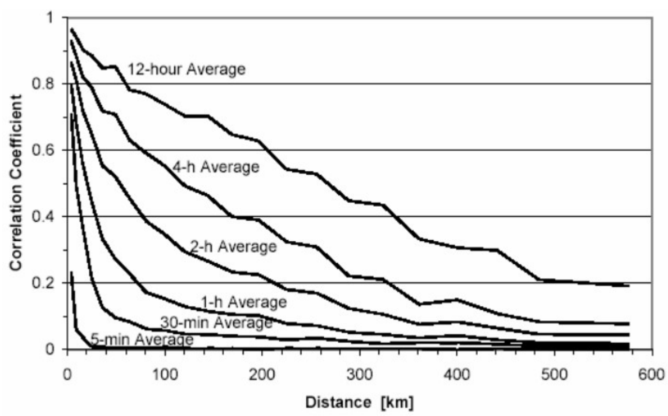

Figure 39 Geographic diversity measured as correlation coefficient as a function of distance and wind aggregation time frames

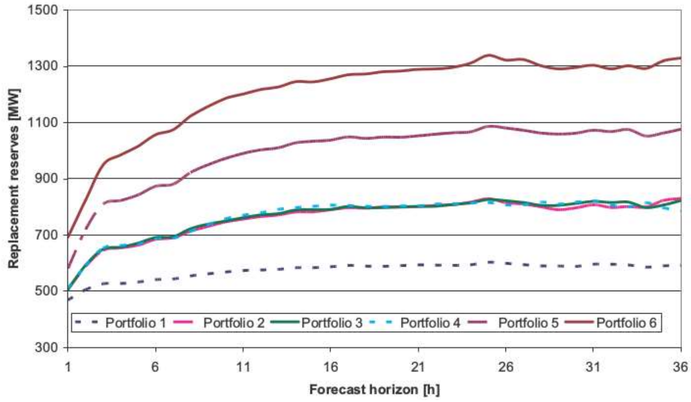

Figure 40 Replacement reserve for the different portfolios (wind penetration) and forecast horizons.

Seasonal and inter-decade variation of energy availability has a significant impact on the effective available capacity of wind generating plant and impacts longer term system adequacy assessment.

Impact on balancing costs

The impact on balancing costs were discussed in [14] and the following figure shows this impact based on experience and wind integration studies:

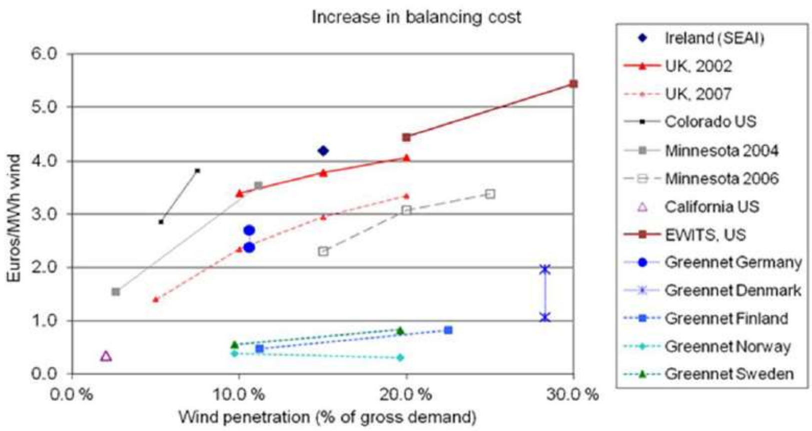

Figure 41 Increase in balancing cost as a function of wind penetration

In most cases, balancing costs increase with an increase in wind penetration – the study notes that: “a general conclusion is that if interconnection capacity is allowed to be used for balancing purposes, then the balancing costs are lower compared to the case where they are not allowed to be used”.

Further that other important factor for reducing costs were:

- Wind aggregation over large geographic areas

- Scheduling the power system closer to the delivery hour

Experience with increase in variable generation

The negative impacts due to the nett load variability associated with high variable generation penetration may be countered through [13][14]:

- Incorporating wind generation into reserve sizing,
- Better forecasting tools
- Development of reserve market ramping products
- Improved operating procedures (i.e. sub-hourly markets),
- Continuous wind power forecasting with dispatch adjustments,
- Flexibility (and smoothing) which is derived from geographic diversity and other flexible sources.

Where these measures and operational procedures are applied, system operators generally experience null to very modest impact on the dimensioning, allocation and costs of system reserves.

For example, in the case of Energinet.dk, the national TSO of Denmark, a system was developed to predict system imbalances based on weather forecast, demand forecast, wind power and solar power prognosis. Based on a 12 hour-ahead predicted imbalance curve, tertiary reserves may be activated or imbalances swapped with neighbours (if possible).

The traditional procedures for activating reserves can be called reactive, while the Energinet.dk's approach can be called proactive. In popular terms the new procedure can be described as "driving looking through the front window" in contrast to "driving looking in the rear view mirror".

Experiences of other European countries with significant wind power shares in the system include [14]:

- Ireland – no additional reserves were required during periods of high wind variability. However, due to frequency and voltage stability constraints, a number of conventional stations are required to remain online
- Spain – the impact on automatic reserves has been minimal, but significant impacts on the manual reserves have been experienced. Spain is building experience and confidence in using probabilistic methods for dimensioning manual reserves.

- Portugal – existing reserve allocation has been increased by 10% of predicted wind power. The additional reserves are supplied through hydro generation and tie-line balancing with Spain.

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Appendix II: Generation capacity

IIa. Exogenous capacity in PDP7 scenario

Plant name	Region	Type	Fuel	Start year	Lifetime	Capacity (MW)
Sơn La	North	Hydro - RES	Water	2011	50	2400
Hoà Bình	North	Hydro - RES	Water	1994	50	1960
Thác Bà	North	Hydro - RES	Water	1975	50	120
Tuyên Quang	North	Hydro - RES	Water	2008	50	342
Bản Vẽ	North	Hydro - RES	Water	2010	50	320
Bản Chát	North	Hydro - RES	Water	2013	50	220
Huội Quảng	North	Hydro - RES	Water	2015	50	260
Lai Châu	North	Hydro - RES	Water	2015	50	400
A Lưới	North	Hydro - RES	Water	2012	50	170
Quảng Trị	North	Hydro - RES	Water	2007	50	64
A Vương	North	Hydro - RES	Water	2008	50	210
Vĩnh Sơn	North	Hydro - RES	Water	1999	50	66
Sông Hinh	North	Hydro - RES	Water	1999	50	70
Pleikrong	North	Hydro - RES	Water	2012	50	100
Yaly	North	Hydro - RES	Water	2003	50	720
Sê San 3	North	Hydro - RES	Water	2006	50	260
Sê San 4	North	Hydro - RES	Water	2009	50	360
Sê San 3A	North	Hydro - RES	Water	2007	50	108
Buôn Tua Srah	North	Hydro - RES	Water	2009	50	86
Sông Tranh 2	North	Hydro - RES	Water	2011	50	190
Srepok 3	North	Hydro - RES	Water	2010	50	220
An Khê - Kanak	North	Hydro - RES	Water	2011	50	173
Buôn Kuôp	North	Hydro - RES	Water	2009	50	280
Sông Ba Hạ	North	Hydro - RES	Water	2009	50	220
Đồng Nai 3	North	Hydro - RES	Water	2011	50	180
Đồng Nai 4	North	Hydro - RES	Water	2012	50	340
Trị An	North	Hydro - RES	Water	1991	50	400
Đa Nhim	North	Hydro - RES	Water	1964	50	160
Thác Mơ	North	Hydro - RES	Water	1995	50	150
Hàm Thuận	North	Hydro - RES	Water	2001	50	300
Đa Mi	North	Hydro - RES	Water	2001	50	175
Đại Ninh	North	Hydro - RES	Water	2008	50	300
Phả Lại 1	North	PC	Domestic Coal	1986	30	440
Khe Bố	North	Hydro - RES	Water	2013	50	100
Phả Lại 2	North	PC	Domestic Coal	2001	30	600
Uông Bí mở rộng	North	PC	Domestic Coal	2011	30	630
Ninh Bình	North	PC	Domestic Coal	1974	30	100
Hải Phòng	North	PC	Domestic Coal	2009	30	1200
Quảng Ninh	North	PC	Domestic Coal	2009	30	1200
Nghi Sơn	North	PC	Domestic Coal	2013	30	600
Vĩnh Tân	North	PC	Import Coal	2014	30	1245
Duyên Hải 1	North	PC	Import Coal	2015	30	1244
Mông Dương 1	North	PC	Domestic Coal	2015	30	1200
Thủ Đức	North	Oil thermal	FO	1965	30	169.5
Cần Thơ	North	Oil thermal	FO	1989	30	37
Ô Môn	North	Oil thermal	DO	2009	30	660

Bà Rịa	North	GTCC	Nam Con Son Gas	1992	30	388
Phú Mỹ 21	North	GTCC	Nam Con Son Gas	1997	30	949
Phú Mỹ 1	North	GTCC	Nam Con Son Gas	2001	30	1140
Phú Mỹ 4	North	GTCC	Nam Con Son Gas	2005	30	468
Thủ Đức	North	GTCC	DO	1965	30	114
Cần Thơ	North	GTCC	FO	1989	30	150
Nậm Chiến 2	North	Hydro - RES	Water	2009	50	32
Bắc Hà	North	Hydro - RES	Water	2012	50	90
Nho Quế	North	Hydro - RES	Water	2012	50	110
Cửa Đạt	North	Hydro - RES	Water	2010	50	97
Chiêm Hóa	North	Hydro - RES	Water	2012	50	48
Sử Pán	North	Hydro - RES	Water	2012	50	34.5
Nậm Phàng	North	Hydro - RES	Water	2012	50	36
Mường Hum	North	Hydro - RES	Water	2011	50	32
Bá Thước	North	Hydro - RES	Water	2012	50	80
Hủa Na	North	Hydro - RES	Water	2013	50	180
Nậm Chiến 1	North	Hydro - RES	Water	2013	50	200
Văn Chấn	North	Hydro - RES	Water	2013	50	57
Tà Thàng	North	Hydro - RES	Water	2013	50	60
Sông Bạc	North	Hydro - RES	Water	2014	50	42
Ngòi Phát	North	Hydro - RES	Water	2014	50	72
Ngòi Hút	North	Hydro - RES	Water	2015	50	48
Nậm Na	North	Hydro - RES	Water	2015	50	66
Nậm Mức 2	North	Hydro - RES	Water	2015	50	44
Na Dương	North	CFBC -	Domestic Coal	2005	30	110
Cao ngạn	North	CFBC -	Domestic Coal	2006	30	115
Cẩm Phả	North	CFBC -	Domestic Coal	2009	30	660
Sơn Động	North	CFBC -	Domestic Coal	2009	30	220
Mạo Khê	North	CFBC -	Domestic Coal	2012	30	440
Mông Dương 2	North	PC -	Domestic Coal	2014	30	1245
Vũng Áng	North	PC -	Import Coal	2014	30	1245
Formosa Hà Tĩnh	North	PC -	Import Coal	2011	30	150
An Khánh	North	PC -	Domestic Coal	2015	30	120
Hương Sơn	North	Hydro - RES	Water	2011	50	34
Thái An	North	Hydro - RES	Water	2011	50	82
Bình Điền	North	Hydro - RES	Water	2009	50	44
Sông Côn	North	Hydro - RES	Water	2009	50	63
Sông Bung 5	North	Hydro - RES	Water	2012	50	57
Sông Bung 4A	North	Hydro - RES	Water	2013	50	49
Sê San 4A	North	Hydro - RES	Water	2011	50	63
KrongH'nang	North	Hydro - RES	Water	2010	50	64
Srepok 4	North	Hydro - RES	Water	2010	50	80
Srepok 4A	North	Hydro - RES	Water	2014	50	64
Đam Bri	North	Hydro - RES	Water	2014	50	75
Hương Điền	North	Hydro - RES	Water	2010	50	81

Đak Tih	North	Hydro - RES	Water	2011	50	144
Đak Mi 4	North	Hydro - RES	Water	2012	50	195
Sông Bung 4	North	Hydro - RES	Water	2014	50	156
Sông Giang 2	North	Hydro - RES	Water	2014	50	37
Đăk Đrinh	North	Hydro - RES	Water	2014	50	125
Đồng Nai 2	North	Hydro - RES	Water	2014	50	73
Bắc Bình	North	Hydro - RES	Water	2009	50	33
Đồng Nai 5	North	Hydro - RES	Water	2015	50	150
Đa Dâng 2	North	Hydro - RES	Water	2010	50	34
Cần Đơn	North	Hydro - RES	Water	2004	50	78
Srokphumieng	North	Hydro - RES	Water	2007	50	51
Hiệp Phước	North	GTCC	Nam Con Son Gas	1998	30	375
Formosa	North	PC	Import Coal	2015	30	310
Phú Mỹ 3	North	GTCC	Nam Con Son Gas	2003	30	740
Phú Mỹ 22	North	GTCC	Nam Con Son Gas	2004	30	740
Nhơn Trạch 1	North	GTCC	Nam Con Son Gas	2008	30	465
Nhơn Trạch 2	North	GTCC	Nam Con Son Gas	2011	30	750
Cà Mau 1	North	GTCC	PM3-CAA Gas	2008	30	771
Cà Mau 2	North	GTCC	PM3-CAA Gas	2008	30	771
VeDan	North	Cogen	Import Coal	2015	30	72
Bourbon	North	Cogen	Bagasse	1997	30	24
Tuy Phong (điện gió)	North	Wind	Wind	2012	25	30
Bạc Liêu (điện gió)	North	Wind	Wind	2012	25	60
Đạm Phú Mỹ	North	Cogen	Nam Con Son Gas	2001	30	21
Hải Phòng II	North	PC	Domestic Coal	2014	30	600
miền Nam	North	Hydro - RES	Water	2015	50	100
Nhạc Hạn	North	Hydro - RES	Water	2014	50	59
Nông Sơn	North	PC	Domestic Coal	2014	30	30
Ô Môn I #2 - FO	North	GTCC	FO	2015	30	330
Sê Ka Man 3 (Lào)	North	Hydro - RES	Water	2015	50	250
Xêkaman 3	North	Hydro - RES	Water	2013	50	250
Thủy điện nhỏ (small hydro)	North	Hydro - ROR	Water	2014	50	1151
Thủy điện nhỏ (small hydro)	North	Hydro - ROR	Water	2014	50	79
Thủy điện nhỏ (small hydro)	North	Hydro - ROR	Water	2014	50	774
A Lin	Center	Hydro - RES	Water	2018	50	62
Bá Thước 1	Center	Hydro - RES	Water	2016	50	60
Bạc Liêu I #1 (*)	South	Wind	Wind	2029	25	600
Bạc Liêu I #2 (*)	South	PC	Import Coal	2030	30	600
Bắc Mê	North	Hydro - RES	Water	2016	50	45
Bảo Lâm 3	North	Hydro - RES	Water	2019	50	46
Cẩm Phả III #1	North	PC	Domestic Coal	2020	30	220
Cẩm Phả III #2	North	PC	Domestic Coal	2020	30	220
Chi Khê	North	Hydro - RES	Water	2017	50	41
Công Thanh	North	PC	Domestic Coal	2020	30	600
Cột nước thấp Phú Thọ	North	Hydro - RES	Water	2023	50	105

Đa Nhim MR (Ext)	Center	Hydro - RES	Water	2018	50	80
Đăk Mi 1	Center	Hydro - RES	Water	2018	50	54
Đăk Mi 2	Center	Hydro - RES	Water	2016	50	98
Đăk Mi 3	Center	Hydro - RES	Water	2016	50	45
Đăk Re	Center	Hydro - RES	Water	2022	50	60
Điện gió Bạc Liêu giai đoạn III	South	Wind	Wind	2018	25	142
Điện gió Hanbaram	South	Wind	Wind	2020	25	117
Điện gió Khai Long (Cà Mau)	South	Wind	Wind	2018	25	100
Điện gió Sóc Trăng	South	Wind	Wind	2019	25	99
Điện gió Trung -Nam	Center	Wind	Wind	2019	25	90
Điện hạt nhân Ninh Thuận I #1	Center	Nuclear	Nuclear	2028	50	1200
Điện hạt nhân Ninh Thuận I #2	Center	Nuclear	Nuclear	2029	50	1200
Điện hạt nhân Ninh Thuận II #1	Center	Nuclear	Nuclear	2029	50	1100
Điện hạt nhân Ninh Thuận II #2	Center	Nuclear	Nuclear	2030	50	1100
Điện sinh khối An Khê #1, biomass	Center	Biomass	Biomass	2017	30	55
Điện sinh khối An Khê #2	Center	Biomass	Biomass	2018	30	55
Đơn Dương #1	Center	Hydro - RES	Water	2030	50	300
Đông Phù Yên #2	North	Hydro - RES	Water	2029	50	300
TBKHH Dung Quất #1	Center	PC	Import Coal	2023	30	750
Duyên Hải II #1 (Coastal Thermal)	South	PC	Import Coal	2021	30	600
Duyên Hải II #2 (Coastal Thermal)	South	PC	Import Coal	2021	30	600
Duyên Hải III extension	South	PC	Import Coal	2019	30	660
Duyên Hải III#1	South	PC	Import Coal	2016	30	600
Duyên Hải III#2	South	PC	Import Coal	2017	30	600
Formosa Đồng Nai #3	South	PC	Import Coal	2016	30	150
Formosa Hà Tĩnh #10	Center	PC	Import Coal	2020	30	150
Formosa Hà Tĩnh #6,7	Center	PC	Import Coal	2020	30	300
Formosa Hà Tĩnh #8,9	Center	GTCC	Import Gas	2020	30	200
Formusa Hà Tĩnh #2	Center	PC	Import Coal	2016	30	150
Formusa Hà Tĩnh #3,4	Center	GTCC	Import Gas	2016	30	200
Formusa Hà Tĩnh #5	Center	PC	Import Coal	2016	30	150
Hải Dương #1	North	PC	Domestic Coal	2020	30	600
Hải Dương #2	North	PC	Domestic Coal	2021	30	600
Hải Hà 2 (cogeneration)	North	PC	Domestic Coal	2022	30	750
Hải Hà 4	North	PC	Domestic Coal	2028	30	600
Hải Phòng III #1	North	PC	Domestic Coal	2025	30	600
Hải Phòng III #2	North	PC	Domestic Coal	2026	30	600
Hòa Bình (EXT) #1	Center	Hydro - RES	Water	2021	50	240
Hòa Bình (EXT) #2	Center	Hydro - RES	Water	2022	50	240
Hóa Dầu Long Sơn #1	South	PC	Import Coal	2017	30	75
Hóa Dầu Long Sơn #2,3	South	PC	Import Coal	2018	30	150
Hồi Xuân	North	Hydro - RES	Water	2018	50	102
Huội Quảng #2	North	Hydro - RES	Water	2016	50	260
Huổi Tạo	North	Hydro - RES	Water	2030	50	180
Kien Giang i	South	GTCC	Nam Con Son Gas	2021	30	750
La Ngâu	Center	Hydro - RES	Water	2018	50	36

Lai Châu #2	North	Hydro - RES	Water	2016	50	400
Lai Châu #3	North	Hydro - RES	Water	2016	50	400
Long An i #1	South	PC	Import Coal	2024	30	600
Long An I #2	South	PC	Import Coal	2025	30	600
Long An II#1	South	PC	Import Coal	2026	30	800
Long An II#2	South	PC	Import Coal	2027	30	800
Long Phú I #1	South	PC	Import Coal	2018	30	600
Long Phú I #2	South	PC	Import Coal	2019	30	600
Long Phú II #1	South	PC	Import Coal	2021	30	660
Long Phú II #2	South	PC	Import Coal	2022	30	660
Long Phú III #1	South	PC	Import Coal	2021	30	600
Long Phú III #2,3	South	PC	Import Coal	2022	30	1200
Lông Tạo	North	Hydro - RES	Water	2017	50	42
Lục Nam #1	North	PC	Domestic Coal	2022	30	50
Lục Nam #2	North	PC	Domestic Coal	2023	30	50
Mỹ Lý	North	Hydro - RES	Water	2021	50	250
Na Dương II #1	North	PC	Domestic Coal	2019	30	50
Na Dương II #2	North	PC	Domestic Coal	2019	30	50
Nậm Củn 1,4,5	North	Hydro - RES	Water	2019	50	65
Nậm Củn 2,3,6	North	Hydro - RES	Water	2020	50	54
Nam Định I #1	North	PC	Domestic Coal	2021	30	600
Nam Định I #2	North	PC	Domestic Coal	2022	30	600
Nậm Mô (VN)	North	Hydro - RES	Water	2020	50	95
Nậm Mô 1 (Laos)	North	Hydro - RES	Water	2026	50	72
Nậm Na 3	North	Hydro - RES	Water	2016	50	84
Nậm Pàn 5	North	Hydro - RES	Water	2020	50	35
Nậm Tóong	North	Hydro - RES	Water	2016	50	34
NĐ đồng phát Hải Hà 1	North	PC	Domestic Coal	2019	30	150
NĐ đồng phát Hải Hà 3	North	PC	Domestic Coal	2025	30	600
NĐ sinh khối Lee &Man	South	Wind	Wind	2018	25	125
Nghi Sơn II #1	North	PC	Domestic Coal	2021	30	600
Nghi Sơn II #2	North	PC	Domestic Coal	2022	30	600
Nho Quế 1	North	Hydro - RES	Water	2016	50	32
Nho Quế 2	North	Hydro - RES	Water	2016	50	48
Ô Môn II	South	GTCC	Nam Con Son Gas	2026	30	750
Ô Môn III	South	GTCC	Nam Con Son Gas	2020	30	750
Ô Môn IV	South	GTCC	Nam Con Son Gas	2021	30	750
Pắc Ma	North	Hydro - RES	Water	2019	50	140
Quảng Ninh III #1	North	PC	Domestic Coal	2029	30	600
Quảng Ninh IIII #2	North	PC	Domestic Coal	2030	30	600
Quảng Trạch I #1	Center	PC	Import Coal	2021	30	600
Quảng Trạch I #2	Center	PC	Import Coal	2022	30	600
Quảng Trạch II #1	Center	PC	Import Coal	2028	30	600
Quảng Trạch II #2	Center	PC	Import Coal	2029	30	600
Quảng Trị #1	Center	PC	Import Coal	2023	30	600
Quảng Trị #2	Center	PC	Import Coal	2024	30	600

Quỳnh Lập I #1	North	PC	Domestic Coal	2022	30	600
Quỳnh Lập I #2	North	PC	Domestic Coal	2023	30	600
Quỳnh Lập II #1	North	PC	Domestic Coal	2026	30	600
Quỳnh Lập II #2	North	PC	Domestic Coal	2027	30	600
Rạng Đông Cogeneration	North	Hydro - RES	Water	2025	50	100
Sêkaman 1- (80%, Lào)	Center	Hydro - RES	Water	2016	50	322
Sekaman sanxay (80%, Lào)	Center	Hydro - RES	Water	2017	50	32
Sêkaman4 (80%,Lào)	Center	Hydro - RES	Water	2018	50	80
Sơn Mỹ I #1	Center	GTCC	Import Gas	2026	30	710
Sơn Mỹ I #2	Center	GTCC	Import Gas	2027	30	710
Sơn Mỹ I #3	Center	GTCC	Import Gas	2028	30	710
Sơn Mỹ II #1	Center	GTCC	Import Gas	2023	30	710
Sơn Mỹ II #3	Center	GTCC	Import Gas	2025	30	710
Sông Bung 2	Center	Hydro - RES	Water	2016	50	100
Sông Hậu I #1	South	PC	Import Coal	2019	30	600
Sông Hậu I #2	South	PC	Import Coal	2019	30	600
Sông Hậu II #1	South	PC	Import Coal	2021	30	1000
Sông Hậu II #2	South	PC	Import Coal	2022	30	1000
Sông Hiếu (Bản Mồng)	North	Hydro - RES	Water	2022	50	60
Sông Lô 6	North	Hydro - RES	Water	2018	50	44
Sông Miện 4	North	Hydro - RES	Water	2018	50	38
Sông Tranh 3	North	Hydro - RES	Water	2016	50	62
Sông Tranh 4	North	Hydro - RES	Water	2016	50	48
Sugar cane Tuy Hòa #1 (Điện sinh khối KCP #1)	Center	Biomass	Biomass	2016	30	30
Sugar cane Tuy Hòa #2 Điện sinh khối KCP #2	Center	Biomass	Biomass	2018	30	30
Tân Phước I #1	South	PC	Import Coal	2027	30	600
Tân Phước I #2	South	PC	Import Coal	2028	30	600
Tân Phước II #1 (*)	South	PC	Import Coal	2028	30	600
Tân Phước II #2 (*)	South	PC	Import Coal	2029	30	600
TBKHH Miền Trung I	Center	GTCC	Import Gas	2023	30	750
TBKHH Dung Quất II	Center	GTCC	Import Gas	2024	30	750
TBKHH Kien Giang II	South	GTCC	Nam Con Son Gas	2022	30	750
TBKHH Miền Trung #3 (nếu khí cho hóa dầu không khả thi)	Center	GTCC	Import Gas	2026	30	750
TBKHH Miền Trung II	Center	GTCC	Import Gas	2024	30	750
TBKHH Sơn Mỹ II #2	Center	GTCC	Import Gas	2024	30	750
Thác Mơ MR (EXT)	Center	Hydro - RES	Water	2017	50	75
Thái Bình I #1	North	PC	Domestic Coal	2017	30	300
Thái Bình I #2	North	PC	Domestic Coal	2017	30	300
Thái Bình II #1	North	PC	Domestic Coal	2017	30	600
Thái Bình II #2	North	PC	Domestic Coal	2018	30	600
Than Vê Đan	South	PC	Import Coal	2016	30	60
Thăng Long #1	North	PC	Domestic Coal	2018	30	300
Thăng Long #2	North	PC	Domestic Coal	2019	30	300
Thiên Tân 1 solar (Ninh Thuận)	Center	Solar	Sun	2019	25	300
Thiên Tân 2 solar (Ninh Thuận)	Center	Solar	Sun	2020	25	400

Thiên Tân 3 solar (Ninh Thuận)	Center	Solar	Sun	2021	25	300
Thượng Kon Tum #1	Center	Hydro - RES	Water	2019	50	110
Thượng Kon Tum #2	Center	Hydro - RES	Water	2019	50	110
Tích năng Bác Ái #1,2	Center	Pumped Hydro	Water	2023	20	600
Tích năng Bác Ái #3,4	Center	Pumped Hydro	Water	2025	20	600
Tích năng Đông Phù Yên #1	Center	Hydro - RES	Water	2028	50	300
Tích năng Đông Phù Yên #3	Center	Hydro - RES	Water	2030	50	300
Trà Khúc 1	Center	Hydro - RES	Water	2017	50	36
Trị An (EXT)	South	Hydro - RES	Water	2025	50	200
Trung Sơn #1,2	Center	Hydro - RES	Water	2016	50	130
Trung Sơn #3,4	Center	Hydro - RES	Water	2017	50	130
Vân Phong I #1	Center	PC	Import Coal	2022	30	660
Vân Phong I#2	Center	PC	Import Coal	2023	30	660
Vĩnh Tân I #1	South	PC	Import Coal	2019	30	600
Vĩnh Tân I #2	South	PC	Import Coal	2019	30	600
Vĩnh Tân III #1	South	PC	Import Coal	2022	30	660
Vĩnh Tân III #2	South	PC	Import Coal	2023	30	660
Vĩnh Tân III #3	South	PC	Import Coal	2023	30	660
Vĩnh Tân IV Extension	South	PC	Import Coal	2019	30	600
Vĩnh Tân IV#1	South	PC	Import Coal	2018	30	600
Vĩnh Tân IV#2	South	PC	Import Coal	2018	30	600
Vũng Áng II #1	Center	PC	Import Coal	2021	30	600
Vũng Áng II #2	Center	PC	Import Coal	2022	30	600
Vũng Áng III #1	Center	PC	Import Coal	2024	30	600
Vũng Áng III #2	Center	PC	Import Coal	2025	30	600
Vũng Áng III #3 (compulsory,not for reserve)	Center	PC	Import Coal	2029	30	600
Vũng Áng III #4 (compulsory,not for reserve)	Center	PC	Import Coal	2030	30	600
Yaly MR	Center	Hydro - RES	Water	2020	50	360
Yên Sơn	North	Hydro - RES	Water	2017	50	70

IIb. Additional exogenous renewable capacity

This total renewable capacity is added in the year indicated. The renewables are divided over the following types and regions:

Year	Renewables capacity (MW)
2015	230
2016	260
2017	360
2018	520
2019	450
2020	470
2021	790
2022	1200
2023	1000
2024	1200
2025	1800
2026	2160
2027	2910
2028	3240
2029	3350
2030	3530

Region	Type	Share
North	Small hydro	8.70%
North	Biomass	1.67%
Center	Wind	39.00%
Center	Solar	12.00%
Center	Small hydro	5.70%
Center	Biomass	1.67%
South	Wind	21.00%
South	Solar	8.00%
South	Small hydro	0.60%
South	Biomass	1.67%
Sum		**100.00%**

IIc. Total capacity of Stated policies, PDP7 and Reserve margin per fuel type and region until 2030 in MW

Year	caseName	Region	Nuclear	Coal_low	Coal_high	Coal_imported	NG_Con_Son	NG_PM3_CN	LNG_imported	Fuel_oil	Light_oil	Bagasse	Rice_husk	Hydro	Wind	Solar	MSW	Grand Total
2015	**Stated policies**	Center				1395							4	6145	90	28		7661
		North		5310	4100								4	8433				17846
		South				2871	6036	1542		517	660	24	4	2704	138	18		14515
	PDP 7	Center				1395							4	6522	90	28		8038
		North		5310	4100								4	8433				17846
		South				2871	6036	1542		517	660	24	4	3776	138	18		15587
	Reserve margin	Center				1395							4	6145	90	28		7661
		North		5310	4100								4	8433				17846
		South				2871	6036	1542		517	660	24	4	2704	138	18		14515
2020	**Stated policies**	Center				2145			400				208	8183	983	975		12894
		North		5310	7950								38	10797				24095
		South				10566	6786	1542		330	660	26	38	2717	1154	183		24002
	PDP 7	Center				2145			400				208	8560	983	975		13271
		North		5310	7950								38	10797				24095
		South				10566	6786	1542		330	660	24	38	3789	1154	183		25072
	Reserve margin	Center				2145			400				208	8183	983	975		12894
		North		5310	7950								38	10797				24095
		South				10566	6786	1542		330	660	26	38	2717	1154	183		24002
2025	**Stated policies**	Center				2145			400				208	9443	3500	975		16671
		North		8329	7950								38	12381				28698
		South				12535	6398	1542		330	660	1216	38	2979	1154	2712		29563
	PDP 7	Center				9015			4820				308	10641	3319	1994		30097
		North		5310	14200								138	11833				31481
		South				20066	8648	1542		330	660	24	138	4025	2412	662		38507
	Reserve margin	Center				2145			400				208	9443	3500	975		16671
		North		10517	7950								38	12381				30886
		South				15882	7205	2385	16806	330	660	1216	38	2979	1154	183	620	49457
2030	**Stated policies**	Center				2145			400				0	9443	9646	975		22609
		North		11613	7950	3617							0	13524	1679			38383
		South				23671	5074	1542		330	0	2062	38	3046	1154	2712		39629
	PDP 7	Center	4600			11415			7700				561	12407	7867	3393		47942
		North		5310	17800								391	13706				37208
		South				24666	8074	1542		330	660		391	4116	5460	1595		46835
	Reserve margin	Center				2145			400				0	10343	10780	975		24644
		North		12029	7950	5249			2966				0	12933	215			41342
		South				25120	5881	2385	16806	330	660	2062	38	3042	1154	183	620	58280

IId Total capacity for Stated policies and scenarios per fuel type and per region in MW

Year	caseName	Region	Nuc-lear	Coal_low	Coal_high	Coal_CCS_low	Coal_CCS_high	Coal_impor-ted	NG_dome-stic	NG_Con_Son	NG_PM3_CN	LNG_impor-ted	Fuel_oil	Light_oil	Bagasse	Rice_husk	MSW	Hydro	Wind	Solar	Grand Total
2020	**Stated policies**	Center						2145				400				208		8183	983	975	12894
		North		5310	7950											38		10797			24095
		South						10566		6786	1542		330	660	26	38		2717	1154	183	24002
	Unrestricted	Center						2145				400				208		8183	983	975	12894
		North		5310	7950											38		10797			24095
		South						10566		6786	1542		330	660	26	38		2717	1154	183	24002
	CO2 cap	Center						2145				400				208		8183	983	975	12894
		North		5310	7950											38		10797			24095
		South						10566		6786	1542		330	660	26	38		2717	1154	183	24002
	CO2 price	Center						2145				400				208		8183	983	975	12894
		North		5310	7950											38		10797			24095
		South						10566		6786	1542		330	660	26	38		2717	1154	183	24002
	CO2 price high	Center						2145				400				208		8183	983	975	12894
		North		5310	7950											38		10797			24095
		South						10566		6786	1542		330	660	26	38		2753	1154	183	24038
	No coal	Center						2145				400				208		8183	983	975	12894
		North		5310	7950											38		10797			24095
		South						10566		6786	1542		330	660	26	38		2717	1154	183	24002
2030	**Stated policies**	Center						2145				400				0		9443	9646	975	22609
		North		11613	7950			3617								0		13524	1679		38383
		South						23671		5074	1542		330	0	2062	38		3046	1154	2712	39629
	Unrestricted	Center						2145				400				0		8903	2900	975	15324
		North		11037	7950			5663								0		13881	803		39334
		South						25800		5074	1542		330	0	2062	38		3046	1154	183	39228
	CO2 cap	Center						2145				400				0		9443	9290	975	22253
		North		11493	7950			3932								0		13524	1679		38578
		South						23396		5074	1542		330	0	2062	38		3046	1154	2890	39532
	CO2 price	Center						2145				400				0		10343	21700	975	35563
		North		12180	7950							522			762	0		12933	2200		36546
		South						16985		5074	1804		330	660	1300	38		3046	6981	9945	46162
	CO2 price high	Center						2145				400				0		10343	21700	4134	38722
		North		5493	7950	4910						1350			1577	0		12960	2200		36439
		South						10566		8128	4111		330	660	485	38		3046	11599	18780	57742
	No coal	Center						2145				400				0		9443	9646	975	22609
		North		11613	7950			3617								0		13524	1679		38383

		South						23671		5074	1542		330	0	2062	38		3046	1154	2712	39629
2040	**Stated policies**	Center						2145				400				0		9923	25302	5273	43042
		North		11769	6714			22184				8441			2	0		13524	2200		64834
		South						37658		6185	7776		330		2060	38		3046	14313	34042	105449
	Unrestricted	Center						2145				400				0		9048	14191	3509	29293
		North		11815	6679			26408				6778			2	0		13881	2200		67762
		South						52342		6314	2222		330		2060	38		3046	1016	3135	70503
	CO2 cap	Center						2145	3722			400				0		9518	24828	1735	42349
		North		11716	6745			20574				9002			2	0		13524	2200		63762
		South						34352		5648	9195		330		2060	38		3046	11012	34311	99992
	CO2 price	Center						2145	2277			400				0		10350	23035	2040	40247
		North		12223	6672			22882				8318			763	0		12933	2200		65992
		South						35819		4282	10221		330		1299	38		3046	6933	27676	89643
	CO2 price high	Center						2145	11877			400				0	153	10444	36802	19807	81627
		North		3188	6150	6811	479	13220				9631			1617	0	419	13013	5019	5487	65035
		South	1572					16547		7411	13660		330		483	0	1134	3046	30300	40591	115074
	No coal	Center						2145	8224			400				0	153	10291	31902	13056	66170
		North		9308	6150	1434	459	3617				20331			40	0	419	13654	5306	10237	70957
		South						23671		5044	9372	4845	330		2060	0	1134	3046	20690	34981	105174
2050	**Stated policies**	Center							11672									10343	43991	10104	76111
		North		12380	7445			37908				12405			2100		419	13524	8881		95061
		South						49647		7421	17985						1134	3046	30300	84352	193885
	Unrestricted	Center							3792									9100	21700	5918	40510
		North		11601	7087			48211				12114			2100			13881	2200		97194
		South						75025		5355	11555							3046	6500	18775	120256
	CO2 cap	Center							16719									9610	44909	14865	86104
		North		12622	6821			35183				14981			2100			13524	5751		90983
		South						48316		7601	17012							3046	30300	79118	185393
	CO2 price	Center							12770									10413	36940	12869	72992
		North		11660	6776			42812				15265			2100			12933	2200		93746
		South						51101		5677	16925							3046	23819	65963	166531
	CO2 price high	Center							17983								153	10721	56041	22045	106942
		North		183	5016	9575	2037	27122				18164			2100		419	13013	11900	47282	136810

	South	22607					22767		6925	16531						1134	3046	30300	61342	164651
No coal	Center							8224								153	10329	52855	17735	89295
	North		6303		4180	5934	3617				45138			2100		419	13654	11900	49327	142573
	South	13801					13105		3788	10531	30484					1134	3046	30300	76176	182365

IIe. Total capacity for Stated policies and sensitivities per fuel type and per region in MW

Year	caseName	Region	Coal_low	Coal_high	Coal_imported	NG_do-mestic	NG_Con_Son	NG_PM3_CN	LNG_imported	Fuel_oil	Light_oil	Bagasse	Rice_husk	MSW	Hydro	Wind	Solar	Grand Total
2020	**Stated policies**	Center			2145				400				208		8183	983	975	12894
		North	5310	7950									38		10797			24095
		South			10566		6786	1542		330	660	26	38		2717	1154	183	24002
	Demand high	Center			2145				400				208		8633	983	975	13344
		North	5310	7950									38		11239			24537
		South			10566		6786	1542		330	660	26	38		2753	1154	183	24038
	Demand low	Center			2145				400				208		8183	983	975	12894
		North	5310	7950									38		10797			24095
		South			10566		6786	1542		330	660	26	38		2717	1154	183	24002
	Demand very low	Center			2145				400				208		8183	983	975	12894
		North	5310	7950									38		10797			24095
		South			10566		6786	1542		330	660	26	38		2717	1154	183	24002
	Low RE cost	Center			2145				400				208		8183	983	975	12894
		North	5310	7950									38		10797			24095
		South			10566		6786	1542		330	660	26	38		2717	1154	183	24002
	NG price low	Center			2145				400				208		8183	983	975	12894
		North	5310	7950									38		10797			24095
		South			10566		6786	1542		330	660	26	38		2717	1154	183	24002
2030	**Stated policies**	Center			2145				400				0		9443	9646	975	22609
		North	11613	7950	3617								0		13524	1679		38383
		South			23671		5074	1542		330	0	2062	38		3046	1154	2712	39629
	Demand high	Center			2145				400				0		10290	11134	975	24944
		North	11325	7950	7837							870	0		12933	2200		43115
		South			26254		5074	1542		330	660	1192	38		3046	1318	8846	48299
	Demand low	Center			2145				0				0		9443	6860	975	19423
		North	11057	7950	401								0		13524	1176		34108
		South			21067		5074	1542		0	0	2062	38		3046	1154	183	34166
	Demand very low	Center			2145				0				0		9600	2574	975	15293
		North	10221	7950									0		13039			31209
		South			16302		4127	1542		0	0	2062	38		3046	1154	183	28453
	Low RE cost	Center			2145				400				0		10343	21700	1655	36244
		North	12459	7950					311			595	0		12960	2200		36475
		South			15710		5074	1542		330	660	1467	38		3046	6981	24166	59013
	NG price low	Center			2145				400				0		9650	9226	975	22396
		North	10909	7950	2044							1093	0		13387	2140		37522
		South			18775		9580	2324		330	660	969	38		3046	1173	2858	39753

2040	**Stated policies**	Center			2145				400				0		9923	25302	5273	43042
		North	11769	6714	22184				8441			2	0		13524	2200		64834
		South			37658		6185	7776		330		2060	38		3046	14313	34042	105449
	Demand high	Center			2145				400				0		10436	28979	8352	50312
		North	11068	6675	30155				9663			872	0		12933	2200		73566
		South			42434		8421	11418		330		1190	38		3046	20630	42525	130031
	Demand low	Center			2145				0				0		9613	21700	4099	37557
		North	11954	6715	11890				5471			2	0		13524	2200		51755
		South			34769		1717	7326		0		2060	38		3046	6933	21793	77682
	Demand very low	Center			2145				0				0		9600	12414	947	25107
		North	13064	6968	11				93				0		13685	2200		36020
		South			24068		1188	2737		0		2062	38		3046	1139	7776	42055
	Low RE cost	Center			2145				400				0		10411	24562	13014	50532
		North	11582	6683	22515				7869			596	0		12960	2200		64405
		South			36845		6263	9579		330		1465	38		3046	6933	54096	118595
	NG price low	Center			2145	9378			400				0		9690	25530	6791	53934
		North	11114	6687	14852				10280			1095	0		13387	2200		59615
		South			30784		6821	9361		330		967	38		3046	12315	35696	99357
2050	**Stated policies**	Center				11672									10343	43991	10104	76111
		North	12380	7445	37908				12405			2100		419	13524	8881		95061
		South			49647		7421	17985						1134	3046	30300	84352	193885
	Demand high	Center				15811								153	10552	50906	16692	94114
		North	13389	7479	48937				17220			2100		419	12933	11900	17858	132235
		South			60578		7457	19447						1134	3046	30300	107251	229213
	Demand low	Center				4348									10100	30230	11633	56311
		North	12161	7197	22445				8111			2100			13524	2200		67738
		South			42087		5975	16141							3046	25935	59805	152988
	Demand very low	Center													9600	21700	664	31964
		North	11997	6997	3794				3048			905			13685	2200		42626
		South			27737		433	6093				1195			3046	4715	19046	62265
	Low RE cost	Center				12335									10566	35492	21750	80142
		North	15230	7574	30183				16986			2100			12960	11900	60872	157805
		South			52712		6790	17681							3046	23732	107946	211907
	NG price low	Center				12606									9916	47162	14011	83695
		North	11587	6675	28110				20815			2100			13387	4602	2295	89570
		South			46605		7859	13492	9995						3046	30300	85037	196333

Appendix III: Transmission capacity

IIIa. Transmission capacity for Stated policies and scenarios

Year	caseName	Central-North (MW)	Central-South (MW)
2015	Stated policies	1800	3500
	Unrestricted	1800	3500
	CO2 cap	1800	3500
	CO2 price	1800	3500
	CO2 price high	1800	3500
	No coal	1800	3500
2020	Stated policies	2744	5379
	Unrestricted	2744	5379
	CO2 cap	2737	5370
	CO2 price	2687	5292
	CO2 price high	2608	4963
	No coal	2744	5379
2025	Stated policies	2744	7879
	Unrestricted	2791	7879
	CO2 cap	2737	7870
	CO2 price	2687	7792
	CO2 price high	2608	7463
	No coal	2744	7879
2030	Stated policies	4973	7879
	Unrestricted	3893	7879
	CO2 cap	4799	7870
	CO2 price	6687	10917
	CO2 price high	6608	11339
	No coal	4973	7879
2035	Stated policies	8045	8079
	Unrestricted	4448	7879
	CO2 cap	8268	8441
	CO2 price	6687	10917
	CO2 price high	10608	14556
	No coal	8973	10518
2040	Stated policies	8045	8079
	Unrestricted	5784	7879
	CO2 cap	8831	8441
	CO2 price	6687	10917
	CO2 price high	14608	16886
	No coal	12973	11932
2045	Stated policies	12045	8079
	Unrestricted	7026	7879
	CO2 cap	12831	11193
	CO2 price	7126	10917
	CO2 price high	18608	16886
	No coal	16973	11932
2050	Stated policies	16045	12079
	Unrestricted	8082	7879
	CO2 cap	16831	15193
	CO2 price	11126	14415
	CO2 price high	22608	16886
	No coal	20973	13370

IIIb. Transmission capacity for Stated policies and sensitivities

Year	caseName	Central-North (MW)	Central-South (MW)
2015	Stated policies	1800	3500
	Demand high	1800	3500
	Demand low	1800	3500
	Demand very low	1800	3500
	Low RE cost	1800	3500
	NG price low	1800	3500
2020	Stated policies	2744	5379
	Demand high	2886	5812
	Demand low	2810	5258
	Demand very low	2764	5229
	Low RE cost	2744	5379
	NG price low	2598	4870
2025	Stated policies	2744	7879
	Demand high	2895	8312
	Demand low	2810	7824
	Demand very low	2764	7729
	Low RE cost	2799	7879
	NG price low	2598	7370
2030	Stated policies	4973	7879
	Demand high	5094	8312
	Demand low	3963	7824
	Demand very low	3046	7729
	Low RE cost	6799	11115
	NG price low	5915	7370
2035	Stated policies	8045	8079
	Demand high	5771	8312
	Demand low	7490	8061
	Demand very low	3711	8009
	Low RE cost	6799	11115
	NG price low	9915	11305
2040	Stated policies	8045	8079
	Demand high	9684	8312
	Demand low	7490	8061
	Demand very low	5286	8162
	Low RE cost	8174	11115
	NG price low	12313	11305
2045	Stated policies	12045	8079
	Demand high	13684	10397
	Demand low	8891	8061
	Demand very low	5579	8162
	Low RE cost	12174	11115
	NG price low	15539	11305
2050	Stated policies	16045	12079
	Demand high	17684	14397
	Demand low	12891	8061
	Demand very low	6156	8162
	Low RE cost	16174	11115
	NG price low	19539	11305

Appendix IV: Economy

IVa. Economy of Stated policies and scenarios

Year	caseName	Trans. Capital Cost – Annualised (m$)	Gen. Capital Cost - Annualised (m$)	Fixed O&M (m$)	Fuel Cost (m$)	Variable O&M (m$)	Grand Total
2015	Stated policies		18	1971	1965	284	4237
	Unrestricted		18	1971	1965	284	4237
	CO2 cap		18	1971	1965	284	4237
	CO2 price		18	1971	1965	284	4237
	CO2 price high		18	1971	1965	284	4237
	No coal		18	1971	1965	284	4237
2020	Stated policies	54	175	3097	3709	375	7411
	Unrestricted	54	175	3097	3709	375	7411
	CO2 cap	54	175	3097	3710	376	7411
	CO2 price	49	175	3097	3719	376	7416
	CO2 price high	36	183	3097	3735	378	7428
	No coal	54	175	3097	3709	375	7411
2025	Stated policies	54	2726	3394	6934	551	13658
	Unrestricted	56	2137	3320	7342	548	13403
	CO2 cap	54	2049	3330	7658	552	13642
	CO2 price	49	2142	3343	7619	555	13708
	CO2 price high	36	3007	3353	7350	547	14293
	No coal	54	2726	3394	6934	551	13658
2030	Stated policies	129	7863	3987	10781	953	23712
	Unrestricted	92	6651	3815	11838	935	23331
	CO2 cap	122	7750	3974	10821	955	23622
	CO2 price	287	10600	4384	8167	1092	24529
	CO2 price high	299	13062	4617	7930	1015	26923
	No coal	129	7863	3987	10781	953	23712
2035	Stated policies	238	16809	4797	14827	1520	38191
	Unrestricted	111	12933	4378	18436	1461	37319
	CO2 cap	257	16263	4719	15281	1555	38076
	CO2 price	287	16586	4787	15182	1505	38346
	CO2 price high	539	23600	5314	13157	1323	43934
	No coal	350	16893	4475	16951	1381	40050
2040	Stated policies	238	26229	5344	19002	2033	52846
	Unrestricted	156	20442	4876	23461	1843	50778
	CO2 cap	276	24856	5097	20296	2016	52542
	CO2 price	287	23685	5044	21136	1939	52092
	CO2 price high	751	35202	6050	16031	1933	59966
	No coal	531	29797	5334	20485	1775	57922
2045	Stated policies	371	37988	5826	23677	2706	70569
	Unrestricted	197	29280	5121	30035	2414	67046
	CO2 cap	501	36548	5490	25282	2538	70360
	CO2 price	302	32198	5215	28108	2619	68442
	CO2 price high	884	52890	6077	18648	2270	80768
	No coal	664	43678	5693	28279	2233	80547
2050	Stated policies	638	52135	6303	28786	3098	90959
	Unrestricted	232	38779	5172	38711	3173	86067
	CO2 cap	768	50656	6016	30006	3131	90578
	CO2 price	552	46242	5672	32541	3174	88182
	CO2 price high	1018	69790	6479	21545	2801	101632
	No coal	846	63598	5693	34084	2702	106923

IVb. Economy of Stated policies and sensitivities

Year	caseName	Trans. Capital Cost – Annual-ised (m$)	Gen. Capital Cost - Annual-ised (m$)	Fixed O&M (m$)	Fuel Cost (m$)	Variable O&M (m$)	Grand Total
2015	Stated policies		18	1971	1965	284	4237
	Demand high		18	1971	1965	284	4237
	Demand low		18	1971	1965	284	4237
	Demand very low		18	1971	1965	284	4237
	Low RE cost		18	1971	1965	284	4237
	NG price low		18	1971	1965	284	4237
2020	Stated policies	54	175	3097	3709	375	7411
	Demand high	73	372	3097	3931	381	7855
	Demand low	52	175	3097	3550	371	7245
	Demand very low	50	175	3097	3522	371	7215
	Low RE cost	54	175	3097	3709	375	7411
	NG price low	32	175	3097	3726	378	7408
2025	Stated policies	54	2726	3394	6934	551	13658
	Demand high	74	3944	3492	7417	601	15529
	Demand low	55	2045	3330	6687	519	12636
	Demand very low	50	1100	3196	6194	455	10995
	Low RE cost	56	2757	3401	6320	523	13058
	NG price low	32	2177	3329	7055	550	13143
2030	Stated policies	129	7863	3987	10781	953	23712
	Demand high	147	10222	4293	11880	1093	27635
	Demand low	93	5769	3724	9785	799	20169
	Demand very low	59	3563	3364	8474	618	16079
	Low RE cost	298	8925	4462	7241	1100	22026
	NG price low	143	7306	3874	11116	909	23348
2035	Stated policies	238	16809	4797	14827	1520	38191
	Demand high	170	21107	5226	16932	1751	45185
	Demand low	219	12576	4349	12612	1322	31078
	Demand very low	91	6306	3582	9170	789	19937
	Low RE cost	298	15193	4929	13578	1566	35564
	NG price low	408	15767	4510	15491	1452	37626
2040	Stated policies	238	26229	5344	19002	2033	52846
	Demand high	300	32491	5961	22048	2430	63232
	Demand low	219	19314	4661	15526	1659	41378
	Demand very low	148	9571	3662	10296	989	24667
	Low RE cost	343	22495	5305	18389	1992	48524
	NG price low	488	25239	4980	19146	1987	51840
2045	Stated policies	371	37988	5826	23677	2706	70569
	Demand high	503	46702	6604	27782	2939	84531
	Demand low	265	28173	4852	18891	2200	54382
	Demand very low	158	14063	3462	11568	1249	30500
	Low RE cost	477	31342	5599	23624	2571	63614
	NG price low	596	37209	5494	23263	2531	69092
2050	Stated policies	638	52135	6303	28786	3098	90959
	Demand high	770	63898	7303	33961	3777	109709
	Demand low	399	38366	4932	22493	2703	68892
	Demand very low	177	18781	3118	12744	1653	36473
	Low RE cost	610	45029	6291	25848	2929	80708
	NG price low	729	50998	5882	28380	3086	89075

Appendix V Imports of fuels

Va. Imported fuel in Stated policies and scenarios

Year	caseName	Imported Coal (PJ)	Imported LNG (PJ)
2015	Stated policies	227	0
	Unrestricted	227	0
	CO2 cap	227	0
	CO2 price	227	0
	CO2 price high	227	0
	No coal	227	0
2020	Stated policies	630	0
	Unrestricted	630	0
	CO2 cap	630	0
	CO2 price	632	0
	CO2 price high	635	0
	No coal	630	0
2025	Stated policies	917	0
	Unrestricted	1009	0
	CO2 cap	873	0
	CO2 price	843	0
	CO2 price high	795	0
	No coal	917	0
2030	Stated policies	1775	0
	Unrestricted	2040	0
	CO2 cap	1774	0
	CO2 price	1082	1
	CO2 price high	674	2
	No coal	1775	0
2035	Stated policies	2713	7
	Unrestricted	3663	3
	CO2 cap	2683	8
	CO2 price	2503	8
	CO2 price high	1006	16
	No coal	1804	61
2040	Stated policies	3324	18
	Unrestricted	4544	11
	CO2 cap	3247	21
	CO2 price	3528	17
	CO2 price high	1615	22
	No coal	1720	281
2045	Stated policies	3898	21
	Unrestricted	5598	21
	CO2 cap	3810	28
	CO2 price	4727	27
	CO2 price high	1801	25
	No coal	1441	816
2050	Stated policies	4517	23
	Unrestricted	6959	22
	CO2 cap	4443	34
	CO2 price	5121	35
	CO2 price high	2190	40
	No coal	930	1230

Vb. Imported fuel in Stated policies and sensitivities

Year	caseName	Imported Coal(PJ)	Imported LNG (PJ)
2015	Stated policies	227	0
	Demand high	227	0
	Demand low	227	0
	Demand very low	227	0
	Low RE cost	227	0
	NG price low	227	0
2020	Stated policies	630	0
	Demand high	657	0
	Demand low	605	0
	Demand very low	602	0
	Low RE cost	630	0
	NG price low	637	0
2025	Stated policies	917	0
	Demand high	991	0
	Demand low	883	0
	Demand very low	811	0
	Low RE cost	784	0
	NG price low	798	5
2030	Stated policies	1775	0
	Demand high	2117	0
	Demand low	1454	0
	Demand very low	1136	0
	Low RE cost	945	1
	NG price low	1425	2
2035	Stated policies	2713	7
	Demand high	3197	14
	Demand low	2193	2
	Demand very low	1366	0
	Low RE cost	2354	7
	NG price low	2124	22
2040	Stated policies	3324	18
	Demand high	3923	21
	Demand low	2651	9
	Demand very low	1527	0
	Low RE cost	3182	14
	NG price low	2794	37
2045	Stated policies	3898	21
	Demand high	4647	22
	Demand low	3024	15
	Demand very low	1650	2
	Low RE cost	3907	16
	NG price low	3490	69
2050	Stated policies	4517	23
	Demand high	5501	30
	Demand low	3380	15
	Demand very low	1727	5
	Low RE cost	3857	26
	NG price low	4008	248