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Analysing techno-economic impacts of integrating wave power to achieve carbon neutrality and electricity based fuel exports: A case for New Zealand

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ABSTRACT

Novel renewable energy technologies will be crucial for mitigating climate change and diversifying future energy systems. Wave power, in particular, has gained significant attention in recent years due to its higher global potential and growing technological maturity. This study analyses the techno-economic impacts of integrating wave power to achieve carbon neutrality and its role in enabling electricity-based fuel exports. Using EP-ALISON-LUT as a modelling tool, New Zealand is chosen as a case country, primarily due to its proximity to the Pacific Island nations and being one of the best sites with high wave power potential. Results show that in a cost-optimised energy system, there is no role of wave power as the system prefers low-cost solar photovoltaics and wind power. However, integrating wave power capacities does not drastically increase the annualised cost, but within the range of 0.9–1.7%. Thus, this cost increase can be weighed against technology diversification and reduction of electricity generation, particularly from solar photovoltaics, and storage requirements from batteries. Exporting e-fuels would require an additional 10% increase in generation capacity, resulting in a modest cost increase, but with a significant opportunity for boosting trade balance and creating additional local jobs.

1. Introduction

Globally, the transition towards integrating renewable energy (RE) technologies is gaining significant traction [1] in response to the climate emergency and to bolster energy security, socio-economic growth, and fulfill Sustainable Development Goals (SDGs) [2]. Many nations have set ambitious targets to reach carbon neutrality by 2050 [1].

To achieve these targets, countries are riding the wave of technological improvements and drastic cost reductions in RE technologies, especially solar photovoltaics (PV) and wind power. The installed capacity of solar PV has grown from 42 GW_p in 2010 to 1420 GW_p in 2023, with an 88% cost reduction [3]. Similarly, wind power has grown from 180 GW in 2010 to 1020 GW in 2023, with a 42% cost decline [3]. Additionally, energy storage technologies, particularly batteries, have seen a rapid cost decline [4]. However, in regions that lack sufficient solar and wind resources or land for installations, other renewable energy technologies that are not yet commercialized will be necessary, especially where the potential for these alternative renewable resources is high.

One of these non-conventional RE resources is wave energy. Wave power has gained significant attention in recent years due to its high global potential and greater technological maturity compared to other ocean energy technologies [5]. According to the analyses by Reguero et al. [6] and Mork et al. [7] global wave power potential is at 32,000 TWh/yr, while Beaumelle et al. [8] show the potential to be between 500 and 17,500 TWh. An economic analysis of wave power potential by Satymov et al. [5] projects wave power cost competitiveness with offshore and onshore wind power. Based on the analysis, by 2050, wave power can provide 29,000 TWh/yr of electricity at <50 €/MWh. High capacity factors are generally observed at sites further away from the equator. The British Isles, South Africa and New Zealand have the best wave power potential and high full load hours (FLH) of 5900, 6400, and 7100, respectively. Thus, with large potential available and stable generation profiles, these countries could become potential hubs for electricity-based fuel (e-fuel) exports.

Countries rich in low-cost renewable resources can produce e-fuels

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for domestic markets and export to countries where land availability is an issue and local e-fuel production is not cost-competitive. These countries are typically islands lacking local resources and are already dependent on fossil liquid fuel imports, primarily used in marine and aviation transport. Keiner et al. have shown for the Seychelles [9] and the Maldives [10] that import of e-fuels is more cost-competitive than local production in a 100% RE-based scenario. Galimova et al. [11] reiterated that global e-fuels and e-chemicals trading can reduce costs by as much as 38% in some e-fuel importing regions in the future. Thus, there is an incentive for smaller countries, especially islands, to import e-fuels, as well as a business case for exporting countries.

1.1. Case country: New Zealand

New Zealand is selected for analysing the impact of wave power integration on the techno-economics of the energy transition towards a 100% RE system by 2050. In addition, a scenario is analysed where New Zealand covers the e-fuel demand in Pacific island countries. More information on the demand from the Pacific islands is given in Section 2.3.1.

New Zealand's share of renewable electricity is already over 80%, almost entirely dominated by hydropower and geothermal [12]. The transport and industrial sectors, on the other hand, are almost entirely dependent on fossil-fuels, with a modest 1.6% share of electric vehicles on the road [13] and most industries relying on coal and natural gas. Residential heating is mainly provided by electric heat pumps (~44% of households), although the use of wood (~30%) and gas (~16%) is still prominent [14].

With New Zealand's "Zero Carbon Bill", which mandates net-zero emissions by 2050 (except for biogenic methane), and the upcoming green hydrogen strategy, there is a nationwide conviction to defossilise the energy system. Looking beyond the decarbonisation of the power and low-temperature heat sectors, the hard-to-abate sectors (transport, especially marine and aviation, and different industrial processes like drying milk or the production of methanol and ammonia) are more complex.

New Zealand is rich in almost every RE resource. Solar PV has a technical potential of 2010 GW_p and onshore wind power of 90 GW [15]. According to the Global Wind Energy Council [16], the offshore wind power potential is 2250 GW, while Satymov et al. [17] calculated the wave power potential as 1900 GW. Thus, there is room to increase the renewable capacity compared to the current installed capacity of 10 GW. This large RE potential could power a defossilised energy system by 2050, while also producing electricity-based hydrogen (e-hydrogen) and e-fuels for both the domestic market and exports to other countries. While there is a target for a net-zero energy system by 2050 and a huge untapped potential of RE, the transition pathway, including e-fuel exports, is still unclear and has not been studied in detail.

1.2. Literature review

Combined, there have been over 1000 publications covering various topics related to the energy transition [18,19]. Yet, distinct gaps remain in better understanding the energy transition and the role of novel technologies. There have been studies integrating wave power, ocean thermal energy conversion (OTEC) and tidal energy into the present power systems operation [20] or studying the temporal complementarity of ocean energy technologies with solar PV and wind power [21]. However, studies with future impact of ocean energy, especially those focussing on the energy systems with high shares of RE is scarce.

The role of wave power in an energy system towards 100% RE was explored for islands such as the Maldives [10] and Seychelles [9], where the potential for wave power is not optimal and for the Hawaiian island of Moloka'i [22] and for entire Hawai'i [23], which has a better potential. These studies found that wave power provided greater diversity and complementarity to the solar PV and wind power dominated systems. Given the land constraints for developing onshore RE technologies on these islands, ocean energy technologies like wave power are beneficial even if the resource quality is not optimal. Similarly, for Galapagos islands [24], Sardinia [25], Azores [26] and Portugal [27] wave power was integrated as part of a 100% RE-based system. However, the authors did not focus on the techno-economic impacts of wave power integration on the energy system, nor discuss its impact on the energy system. A study for Portugal [27] concludes that a 100% RE system favours more of hydropower and wind power, while a study for the British Isles [28] considered wave power during the energy transition to 100% RE by 2050 and found that wave power could become an important technology, if it becomes cost-competitive to wind power and solar PV. However, they point that it could provide diversity and resilience to the energy system. Other studies which focused only on the power sector transition without sensitivity analysis related to wave power integration were not considered [27]. Most of the literature included wave power in the context of islands without looking at its potential as well as its techno-economic impact during the energy transition. Thus, studies are scarce exploring the role of wave power in an energy transition in the context of larger countries having good potential for its exploitation.

Various modelling tools have been developed and used for the analysis of energy systems [29]. However, in this study EnergyPLAN [19,30] is used as a modelling tool due to its ability to simulate integrated smart energy systems with power, heat, transport, and industry sectors on hourly resolution. Compared to other modelling tools, it simplifies data requirements by aggregating units into representative units, it has an ability to quickly simulate various user-defined scenarios with transparency on how scenarios are developed, and it can be combined and executed as a function with Matlab [31]. As to the applicability of EnergyPLAN, Meschede et al. [32] focus on a comprehensive review of 100% RE scenarios for islands and conclude that EnergyPLAN is mostly used for island energy system analysis. Similarly, Prina et al. [33] and Østergaard et al. [34] highlight the extensive applicability of EnergyPLAN for both islands and larger countries. Finally, Majidi et al. [35] conclude that EnergyPLAN is among the tools that fulfils the requirements to analyse future smart energy systems.

The complexity of an energy model influences the detailed insights gained and thus their applicability and replicability to real world conditions. Over the period of time the complexity of energy system modelling has been growing. As pointed out by Østergaard et al. [34] the level of complexity in EnergyPLAN has evolved from analyses of CHP systems with varying degrees of RES penetration to analyses of fully integrated smart energy systems, including flexibility analysis across all sectors. However, there are limitations on the use of EnergyPLAN and its main limitation is that it is a simulation tool [36]. In other words, it is up to the skills of the user to find "optimal" solutions [37], which besides yielding sub-optimal results, is rather time consuming. To overcome this issue, the EnergyPLAN tool has been coupled with various other optimisation algorithms to better explore the near-optimal solution space [38].

Currently, much focus is on hydrogen to decarbonise the hard-to-abate sectors [39–41], as hydrogen will be a key energy carrier in the Power-to-X Economy [42]. However, its role is mainly limited to an intermediate energy carrier for e-fuels and e-chemicals production [43]. Another study, with the tool REMix, aimed to find the optimal gas pipelines for hydrogen to enable European energy autonomy [44]. Recent sector-coupled modelling with PyPSA [45] found that quicker scaling of electrolyser and renewable capacities than planned by the European Commission would result in lower system costs and levelised costs of hydrogen.

For the case of New Zealand, existing research highlights both the potential and challenges of large-scale integration of renewables in the energy system. Mason et al. [46,47] demonstrate that a combination of hydropower, wind power, geothermal, and biomass can meet the 100% RE target, though they note issues like wind spillage and the necessity for effective peaking strategies. Walmsley et al. [48] analyse greenhouse gas emissions in relation to energy return on investment. Meschede et al. [32] review various 100% RE scenarios for islands, including New Zealand, and stress the necessity for substantial energy storage and system flexibility while finding limited benefits from interconnecting with Australia due to New Zealand's strong renewable resources. Sovacool and Watts [49] discuss the technical feasibility and potential benefits of transitioning to a fully RE system for New Zealand, highlighting the challenges related to decentralisation and increased fossil fuel dependence. Mohseni et al. [50] offer a case study of Rakiura--Stewart Island, showcasing a sustainable off-grid multi-carrier microgrid solution that significantly reduces costs compared to diesel. Finally, Bahrami Gholami et al. [51] and Poletti and Staffell [52] explore the roles of wind power and geothermal energy in achieving high levels of renewable integration, and recommend additional capacity and grid improvements.

1.3. Novelty and contributions

While there have been numerous studies on energy system transition for the power sector, looking at fully integrated power-heat-transport transitions has only caught attention in the last couple of years. Furthermore, the impact of wave power as a technology on energy system integration and transition towards 100% RE is missing, especially for countries with high wave power potential. To represent a group of such countries, New Zealand's energy system is analysed with integration of different sensitivities of wave power. In addition, the case country New Zealand is rich in a variety of renewable energy resources, such as hydropower, geothermal, wind energy, solar energy, and wave energy. Thus, wave power has the potential to diversify the generation mix. This work contributes to the existing body of knowledge by.

- Assessing and comparing a cost optimisation scenario with scenarios integrating various capacities of wave power with respect to cost of the energy system for 2030 and 2050, as a potentially valuable RE resource that has been overlooked so far.
- Studying the technical aspects of wave power integration with respect to the total generation and storage capacity required.
- Analysing the impact of additional e-fuel production demand on the total cost and additional power capacities required to be built. This study comprises two milestone years, 2030 and 2050, next to the base case 2020, to show how New Zealand's energy system could evolve.
- Showcasing and comparing scenarios for a 100% RE system in New Zealand integrating power, heat, transport, and industry sectors. This includes investigating the role of e-hydrogen and e-fuels, especially in hard-to-abate sectors for the domestic market, and the export potential of e-fuels to Pacific islands. Altogether, this is the first study to look at a fully integrated, 100% RE-based system for New Zealand, including export options.

The following section details the methodology, based on an optimisation add-on for EnergyPLAN (EP) that optimises RE capacities, electricity, and the hydrogen sub-system, as well as the modelling setup, inputs, and scenario definitions. Section 3 details the results related to optimal sizes and system costs, while Section 4 discusses them in the broader literature. Section 5 concludes the study.

2. Methodology and data

The EnergyPLAN Add-on for LInear System OptimisatioN by LUT (EP-ALISON-LUT) has been used to add an optimisation function to EP [9,31]. Thus, extending from a deterministic simulation tool to an optimisation tool capable of finding the optimal portfolio of generation, storage and flexibility options [53,54].

In the following sections, the EP-ALISON-LUT model will be explained with its key equations, different scenario assumptions, the input data and the financial and technical assumptions used.

2.1. Modelling framework

EP-ALISON-LUT was developed to assess various techno-economic scenarios and possible sensitivities of different RE technologies in future energy systems across various countries based on a linear optimisation. The primary objective is to define a least-cost energy system incorporating various renewable electricity generation, storage and other flexibility providing technologies [18,55] for a selected future year. The model assumes a 'greenfield' approach for installing the required capacity for 2030 and 2050, with costs allocated over the technical lifetime of the installed technology.

The tool is based on a linear optimisation algorithm on an hourly resolution of various RE supply technologies, different electricity storage technologies including the functionality of smart charging and V2G and the hydrogen balance system for any year. Due to the strong coupling the simulation results from EP are taken as inputs to EP-ALISON-LUT for further modelling.

Fig. 1 shows the interaction and feedback loop between EP and ALISON-LUT. EP calculates the electricity dispatch from large conventional power plants (PP) and combined heat and power (CHP) with their total cost, as well as the hydrogen demand (in heating, transport, and industry as part of the hydrogen demand) and feeds them to EP-ALISON-LUT, which then optimises electricity generation and storage capacities, hydrogen production, and respective energy flows in an overnight transition. A detailed documentation of the model including its code and step-by-step utilisation is available from an online repository [56].

2.1.1. Objective function and technical balances

The linear optimisation problem minimises the total annual energy system costs (Eq. (1)), adapted from Keiner et al. [56,57]. These total costs include the annual cost of installed capacities for renewable electricity generation and storage, hydrogen production, andstorage. Cost of batteries within the battery electric vehicles (BEVs) with vehicle-to-grid (V2G) functionality is not part of the cost analysis, as this cost is not always considered to be part of an energy system cost analysis. However, the variable operational cost associated with using the batteries as part of the V2G is fully considered and it is set to 0.2 €/MWh.

$$\min\left(\sum_{t\in tech}\left(\frac{Cap_t\cdot CAPEX_t}{1-(1+i)^{-N}}+OPEXfix_t\cdot Cap_t+OPEXvar_t\cdot E_{gen,disch,t}\right)\right.$$
$$\left.+\sum_{f\in efuel}\left(eLF_{export,f}\right)\right) \tag{1}$$

Abbreviations: t – technology; Cap_t – Installed capacity; $CAPEX_t$ – capital expenditures of technology (t); i – interest rate; N – lifetime, $OPEXfix$ – fixed operational expenditures; $OPEXvar$ – variable operational expenditures; $E_{gen,\ disch}$ – generated or discharged electricity of technology; f – fuel; eLF_{export} – exported liquid e-fuel.

The target function represented in (Eq. (1)) calculates the total annualised cost of the renewable electricity and hydrogen system, summing up the variables represented in the energy balance of supply and demand on an hourly resolution as represented in (Eq. (3)). The annual cost of the technologies modelled in EP, as shown in Fig. 1, are read from the result file by EP-ALISON-LUT and added to the final annual costs.

2.1.2. Electricity and hydrogen balances

The main constraints are matching the supply with demand for every hour of the year, for the vectors of electricity and hydrogen. The total electricity demand (Eq. (2)) consists of the basic power demand, electricity used for cooling, other uses of electricity such as electric vehicle (EV) charging, direct electricity-based heating, electricity demand for

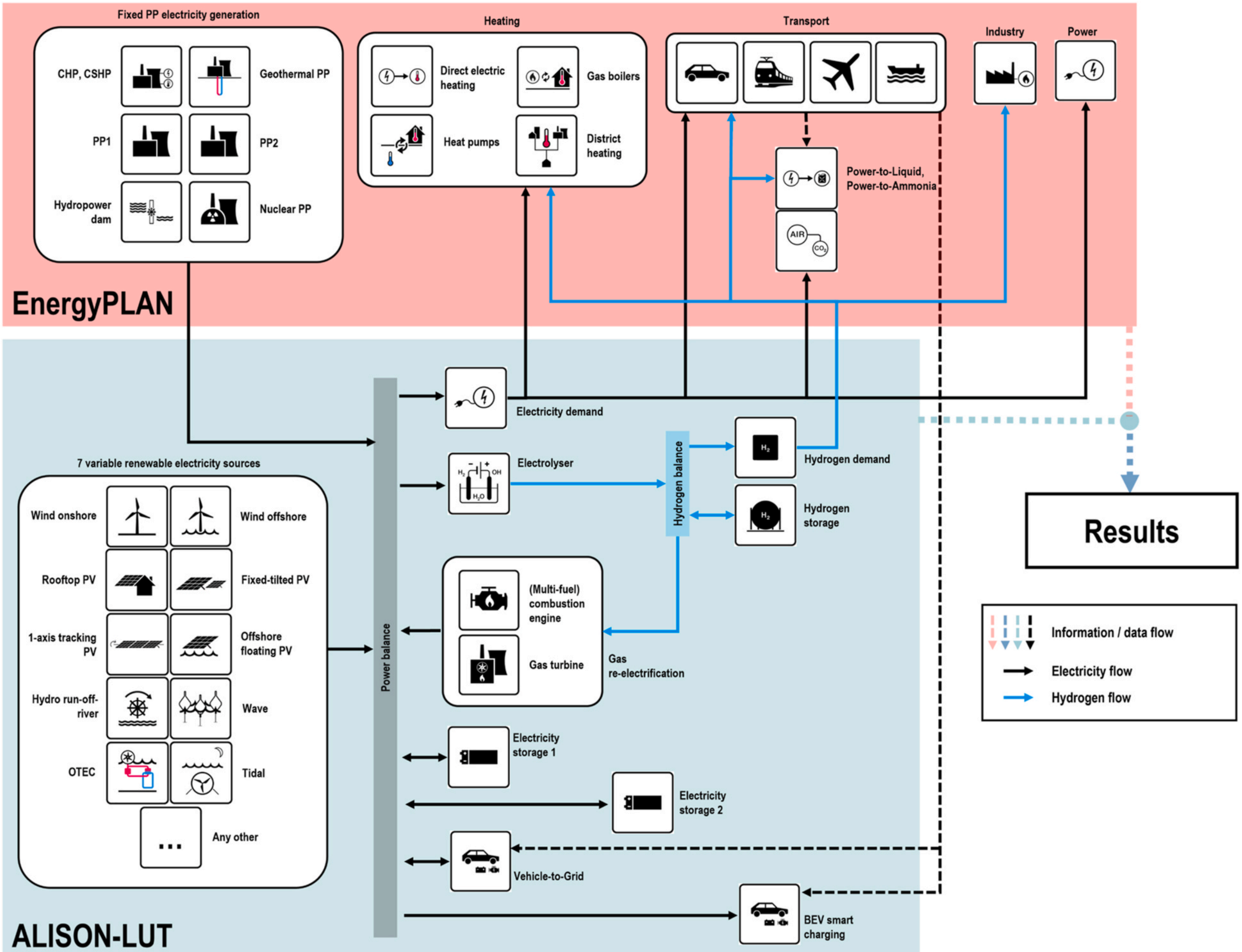

Fig. 1. A schematic of different components and energy flows in the EP-ALISON-LUT framework and the data flow between the two models [56].

heat pumps, electricity demand for direct air capture (DAC) and electricity for ammonia (e-ammonia; NH_3) synthesis. Additionally, the cumulative electricity demand is taken from the EP model to the EP-ALISON-LUT prior to the optimisation process.

$$\forall h \in [1, 8784] : El_{demand,h} = El_{power,h} + El_{cooling,h} + El_{flex,h} + El_{HP,h} + El_{DAC,h} + El_{NH3,h} \tag{2}$$

Abbreviations: El_{demand} – cumulative electricity demand (imported from EnergyPLAN), El_{power} – electricity demand of power sector, $El_{cooling}$ – electricity demand for space cooling, El_{flex} – flexible electricity demand (as defined in EP), El_{HP} – electricity for heat pumps, El_{DAC} – electricity demand for direct air capture, El_{NH3} – electricity demand for ammonia synthesis. For every hour of the year, the total electricity generation, discharge from storage technologies and electricity imports must be able to satisfy the total electricity demand (Eq. (3)).

$$\forall h \in [1, 8784] : \sum_{RES=1}^{7} El_{gen,RES,h} + \sum_{stor=[1,2]} \left(El_{stor,h}^{disch} \cdot \eta_{stor}^{disch} \right) + Gas_{elec,h} \cdot \eta_{elec,Gas} + El_{V2G,h}^{disch} \cdot \eta_{V2G}^{disch} + El_{PP,h} + El_{import,h} - \sum_{stor=[1,2]} El_{stor,h}^{charge} - El_{WEL,h} - El_{V2G,h}^{charge} - El_{SCV,h} - El_{exc,h} \tag{3}$$

Abbreviations: $El_{gen,RES}$ – electricity generated by RE source, El_{stor}^{disch} – electricity discharged from electricity storage, η_{stor}^{disch} – discharge efficiency of electricity storage, Gas_{elec} – gas for re-electrification, $\eta_{elec,Gas}$ – efficiency of gas re-electrification, El_{V2G}^{disch} – electricity discharged from V2G, η_{V2G}^{disch} – discharge efficiency of V2G, El_{PP} – electricity from dispatchable PP, El_{import} – electricity import, El_{stor}^{charge} – electricity charged to electricity storage, El_{WEL} – electricity consumed by water electrolyser, El_{V2G}^{charge} – electricity charged to V2G, El_{SCV} – electricity charged to smart charging EVs, El_{exc} – excess electricity or electricity export.

The total cumulative hydrogen demand consists of hydrogen use in power plants, heating, industry and as a feedstock for e-fuels within the energy system and is imported from the EP model to EP-ALISON-LUT prior to the optimisation process. The hydrogen balance constraint is given in Eq. (4). The model does not account for the actual quantity of water used in the electrolysers for hydrogen production.

$$\forall h \in [1, 8784] : H2_{WEL,h} + H2_{stor,h}^{disch} - H2_{stor,h}^{charge} - H2_{elec,h} = H2_{demand,h} \tag{4}$$

Abbreviations: $H2_{WEL}$ – hydrogen from the water electrolyser, $H2_{stor}^{disch}$ – hydrogen discharged from hydrogen storage, $H2_{stor}^{charge}$ –

Table 1
Overview of the applied main scenarios and sub-scenarios with description and key assumptions.

Scenario	Description	Key assumptions	Sub-scenarios
Milestone year 2030 – power sector decarbonisation (MY-2030)	Based on NZ's goal of eliminating fossil fuels in the power sector by 2030 [58], as part of the net zero 2050 target [59]. Already, the share of RE in the power sector is more than 80%, based primarily on hydropower and geothermal with a small share of wind power. Therefore, the subsequent step to decarbonise the power system is getting rid of the remaining share of coal and gas in the power generation plus meeting the increasing demand. This scenario shows the techno-economic impact of power sector decarbonisation on the energy system.	Complete phase-out of coal from the power and heating sector. Coal demand in the industry sector reduces from 17% in 2020 to 10% in 2030. Oil demand in residential heating reduces from 13% in 2020 to 7% in 2030, while in the transport sector it reduces from 100% to 46% with an increase in electrification and liquid e-fuel production.	Free cost optimisation (FCO) Capacity addition of wave power in a resolution of 0:250:2000 MW
A 100% RE-based system in 2050 (RE-2050)	Based on the government's target of net-zero emissions by 2050 across the entire energy system, excluding biogenic methane emissions [58].	Net-zero emissions in the energy system. Complete phase-out of fossil fuel technologies in all sectors. Use of abundant RE potential for domestic production of green e-hydrogen and e-fuels. Depending on the scenario, once built capacities for onshore wind power and pumped hydro energy storage in 2030, will be the lower limit for the particular scenario, due to long lifetimes and realistic accounting of existing infrastructure in 2050.	Free cost optimisation (FCO) Capacity addition of wave power in a resolution of 0:250:2000 MW
A 100 % RE-based system in 2050 with e-fuel exports to Pacific Islands (RE-2050-eFe)	Similar to the RE-2050 scenario with an additional assumption that New Zealand explores business opportunities to export e-fuels to Pacific Islands to cover their 100% of their e-fuels demand volumes in 2050. As these islands already depend on larger economies for energy and trade, New Zealand could exploit its RE potential for e-fuel production and export.	Net-zero emissions in the energy system. Complete phase-out of fossil fuel technologies in all sectors. Use of abundant RE potential for-2050 scenario, with domestic production of green e-hydrogen and e-fuels Exports of e-fuels to the Pacific Islands. Depending on the scenario, once built capacities for onshore wind and pumped hydro energy storage in 2030, will be the lower limit for the particular scenario, due to long lifetimes and realistic accounting of existing infrastructure in 2050.	Free cost optimisation (FCO) Capacity addition of wave power in a resolution of 0:250:2000 MW

hydrogen charged to hydrogen storage, $H2_{elec}$ – hydrogen to gas re-electrification, $H2_{demand}$ – cumulative hydrogen demand (imported from EnergyPLAN).

Additional constraints on different technologies and energy flows are given in the supplementary material (SM) Section 1.

2.2. Scenario framework

Five main scenarios were designed for this study: a Reference scenario (RF) year 2020, Milestone year 2030 – power sector decarbonisation (MY-2030), a net-zero RE-based system in 2050 (RE-2050), and a net-zero RE-based system in 2050 with e-fuel exports to Pacific Islands (RE-2050-eFe). In all the scenarios, sensitivities of wave power [5] were explored with incremental increases in capacity, (from 0 to 2000 MW in steps of 250 MW). Additionally, a free cost optimisation (FCO) with all available technologies is done (no constraints on emissions). A FCO represents a scenario where the model optimises the least cost energy mix, without constraints on any technology. A detailed description of all these scenarios is provided in Table 1.

2.3. Demand projections

The estimation of future energy demand for 2030 and 2050 is based on a long-term projection developed by Keiner et al. [60] using the LUT-DEMAND model. The "delayed economic equality scenario" (LUT-DEES) was used in combination with the United Nations medium population projection [61]. Table 2 provides the cumulative demand projections for the power, heating, transport and industry sectors in 2030 and 2050, with actual demands for 2020.

The heating energy demand, which is space heating and water heating demand in residential houses and commercial establishments, transitions away from fossil fuels to increased heat pump and direct electricity-based heating. In 2050, about 5% of the total heat demand is satisfied by boilers, using electricity-based methane (e-methane) and sustainable biomass.

The large-scale shift from internal combustion engines to EVs results in efficiency improvements and a reduction in total final energy demand in the transport sector. Road transportation such as passenger cars, buses, and light and medium duty trucks shift towards electrification. Hard-to-abate transport modes such as long-distance marine and aviation transition to using e-fuels (e-ammonia, e-methanol and e-kerosene jet fuel), and bio-fuels due to the large-scale availability of biomass [62].

Currently, the industrial sector accounts for the second largest share of final energy consumption, with the main sources of fuel supply coming from natural gas and coal. The government plans to shift away from fossil fuels through investments in energy efficiency, fuel switching to green e-hydrogen and e-methane and, wherever possible, direct electrification [63]. The industry sector could transition towards e-ammonia, e-methanol, e-hydrogen and biomass as shown in Table 2.

2.4. e-fuel demand for the Pacific islands

As described in Section 2.2, in addition to local production and consumption of e-fuels in 2050, a scenario with e-fuel export to the Pacific islands was modelled. This scenario assumes that all the e-fuel demand in the Pacific islands will be imported from New Zealand. The total demand in terms of energy units of liquid e-fuels (liquid e-hydrocarbons, e-ammonia, and e-methanol) in 2050 is given in Table 3 for the Pacific islands. Refer to SM Section 2.6 for detailed assumptions and calculations.

2.5. Renewable energy resources: profiles and potentials

The RE technologies included in modelling New Zealand's future energy systems are rooftop solar PV, ground-mounted large-scale solar PV divided into optimally fixed tilted and single-axis tracking PV plants, onshore and offshore wind power, hydropower, and wave power as a novel technology. This study does not consider the large-scale expansion of geothermal power, despite potential for further power generation [64].

As the modelling in EP and EP-ALISON-LUT is based on an hourly resolution, the RE generation profiles are also calculated on an hourly

Table 2
Final energy demand for 2020 and projections for 2030 and 2050. Demand estimations based on [60].

Sector	Final energy demand	Unit	2020	2030	2050[b]
Power	Electricity[c]	TWh_{el}	32.4	32.9	40.8
Heat	Coal	TWh_{th}	0.2	0.0	0.0
	Oil	TWh_{th}	3.1	2.1	0.0
	Natural gas	TWh_{th}	3.4	2.9	0.0
	Biomass	TWh_{th}	2.0	2.3	1.9
	Electricity	TWh_{el}	10.7	13.1	15.2
	Total	**TWh**	**19.4**	**20.4**	**17.1**
Transport	Petrol	TWh_{th}	24.3	11.7	0.0
	Diesel	TWh_{th}	29.5	11.7	0.0
	Kerosene/Jet fuel[a]	TWh_{th}	19.5	22.3	0.0
	LPG	TWh_{th}	0.0	0.0	0.0
	e-Petrol	TWh_{th}	0.0	12.0	0.0
	e-Diesel	TWh_{th}	0.0	12.0	6.9
	e-Kerosene/Jet fuel	TWh_{th}	0.0	2.5	35.5
	e-Hydrogen	TWh_{th}	0.0	0.2	3.3
	e-Methanol	TWh_{th}	0.0	0.0	19.8
	e-Ammonia	TWh_{th}	0.0	0.0	3.1
	Biodiesel	TWh_{th}	0.0	0.0	0.6
	Electricity	TWh_{el}	0.1	2.1	15.5
	Total	**TWh**	**73.4**	**74.5**	**84.7**
Industry	Coal	TWh_{th}	6.5	4.6	0.0
	Oil	TWh_{th}	10.5	10.7	0.0
	Natural gas	TWh_{th}	14.9	14.7	0.0
	Biomass	TWh_{th}	4.4	2.2	1.1
	e-Hydrogen	TWh_{th}	0.0	0.5	4.9
	e-Methanol	TWh_{th}	0.0	2.5	16.3
	e-Ammonia	TWh_{th}	0.0	0.1	4.7
	Total	**TWh**	**36.3**	**35.3**	**27.0**
	Total Final energy demand	**TWh**	**161.5**	**163.1**	**169.6**

[a] Includes domestic and international aviation demand.
[b] Represents the RE-2050 scenario. For the RE-2050-eFe, additional demand from Table 3 is added to the respective fuel categories.
[c] Excluding electricity for heating and transport.

resolution, as explained below for wave power and in sections 2.4 and 2.5 for other technologies.

The calculation of the technical potential for wave power is based on the utilisation of the exclusive economic zone (EEZ) for offshore technology installations. Satymov et al. [17] used a specific type of wave energy converter; C4 developed by CorPower, with a specific capacity density of 14.8 MW/km^2. The methodology to calculate the hourly capacity factor profile for wave power focuses on sites with the best to least potential and calculating a weighted average. The top 20% of the sites are weighted with 0.3, the next 10% with 0.2 and the next 20% with 0.1, while bottom 50% of the sites are not considered. Similarly, the profile for offshore wind power is calculated using sites with the lowest levelised cost of electricity (LCOE) and with the same weight distribution. This method allows for a close to reality, composition of the resource quality, as confirmed by Hedenus et al. [65] on the case of wind power. This method only aggregates the spatial resolution at any point in time, as the temporal resolution remains intact for any location in the region. The hourly generation profile in a 0.45° x 0.45° spatial resolution for wave power is calculated based on the methodology described in Satymov et al. [17]. The resource potential map and the hourly profile for wave power are given in Fig. 2.

2.6. Storage and flexibility technologies

Flexibility to the energy system [18] is provided by Li-ion batteries (prosumer and utility-scale, which balance short-term variability) [66] and pumped hydro energy storage (PHES, which provides short to mid-term flexibility) [66]. For seasonal variability, hydrogen storage is used. It serves a dual purpose: as a storage for fuel used in internal combustion engines (ICE) to balance the power system and as a buffer storage for e-fuel production [67–69]. Additionally, flexibility is

Table 3
Total e-fuel demand segregated according to different fuel types across the Pacific islands considered in this study.

	Unit	2050
e-Diesel	$TWh_{FTL,LHV}$	1.2
e-kerosene/jet fuel	$TWh_{FTL,LHV}$	5.4
e-Liquified Natural Gas (LNG)	$TWh_{th,LHV}$	0.1
e-Methanol	$TWh_{MeOH,LHV}$	5.8
Total	$TWh_{th,LHV}$	12.4

Abbreviations th – thermal; LHV – lower heating value; FTL – Fischer Tropsch liquids; MeOH – methanol.

provided by demand response [70], smart charging [71] and vehicle-to-grid (V2G) operation [72].

The available potential of V2G storage and the interface capacity is estimated based on the share of vehicles with smart charging enabled, registered vehicles (and their growth in 2030 and 2050), phase-in of different powertrains, average battery capacities and interface capacities per vehicle type. These assumptions are given in detail in Bogdanov et al. [73].

2.7. Technical and financial assumptions

Table S1 in the SM provides a comprehensive list of all technical and financial assumptions, for the different target years (2020, 2030, 2050). The financial assumptions mainly consist of capital expenditures (capex), fixed and variable operational expenditures (opex fixed and opex variable), and fuel costs. The technical assumptions consist of the lifetime of technologies and efficiencies. For wave power the financial and technical assumptions are given in Table 4.

3. Results

The results are shown for the milestone year 2030 (MY-2030), the fully defossilised system in 2050 (RE-2050), and the additional demand for e-fuel exports (RE-2050-eFe) to the Pacific Islands. The power capacity requirements are presented (Section 3.1), followed by the storage requirements (Section 3.2), and the costs (Section 3.3) of shifting to a fully RE system.

3.1. Power capacity expansion and electricity generation

The total electricity generation grows by almost 2.5 times from 43.1 TWh in 2020 to 109 TWh in 2030, and by 4.9 times to 214 TWh in 2050 (RE-2050). This is due to a rapid shift towards electrification and a large-scale increase in demand across all sectors. Correspondingly, the installed capacity of power-generating units needs to grow rapidly. This can be seen in Fig. 3 for the scenarios MY-2030, RE-2050, and RE-2050-eFe.

Comparing the RE-2050 and RE-2050-eFe's FCO sub-scenarios, the e-fuel export case requires an additional 17.1 GW installed capacity.

Fossil fuel generating capacities are fully decommissioned and the optimisation shows a large growth in solar PV technologies, with a share of 79.9%, 81.6%, and 83.8%, in total installed capacity in the MY-2030, RE-2050 and RE-2050-eFe FCO sub-scenarios, respectively. Among the solar PV technologies, single-axis tracking grows at the fastest rate, and in 2030 almost the entire utility-scale PV capacity (33.4 GW) is based on this technology, while other solar PV technologies, like optimally fixed tilted (0.4 GW), are not part of the optimum (FCO scenario). For rooftop solar PV, the capacity was pre-defined, and it is assumed that it will grow to 1.5 GW by 2030 and 3 GW by 2050 [74]. The total rooftop PV capacity includes residential, commercial, and industrial installations. The rooftop solar PV capacity was 0.16 GW in 2020 and it has seen the fastest growth during the early 2020s due to fast-falling costs and other factors [74]. To capture this trend, rooftop PV capacity increases by 2030. Even for the RE-2050 and RE-2050-eFe FCO scenarios, single-axis tracking solar PV has the largest share of the total installed capacity with 47%

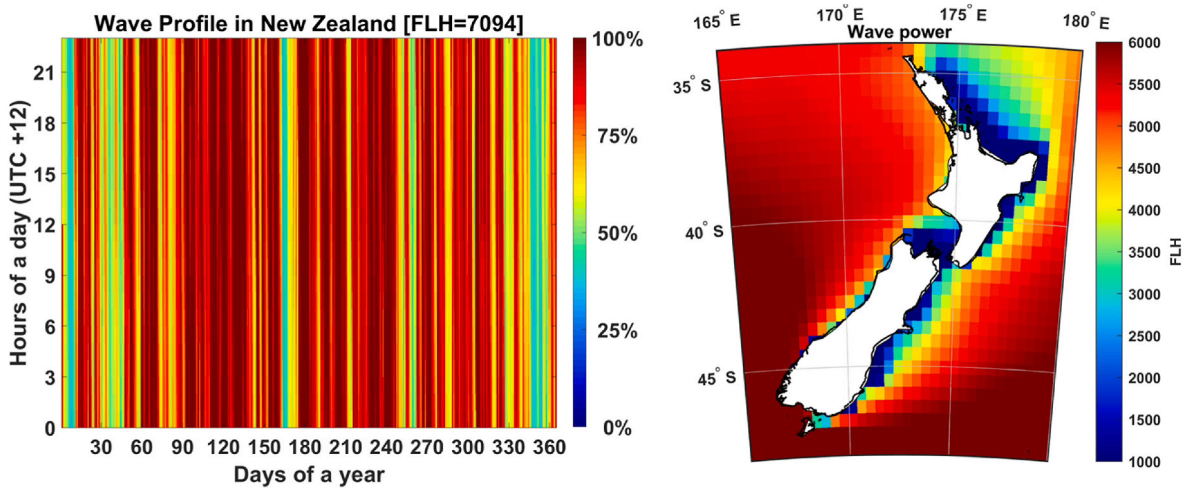

Fig. 2. Capacity factor profiles for wave power on an hourly resolution for a year and resource distribution with full load hours (FLH).

Table 4
Techno-economic input data used for wave power in the modelling and applied to all the scenarios.

Technology	Parameter	Unit	2020	2030	2050	Source
Wave power	capex	€/kW		2800	1800	[17]
	opex fixed	% of capex		2.75	2.4	
	opex variable	€/(kWh•a)				
	lifetime	years		25	30	
	correction factor	–				

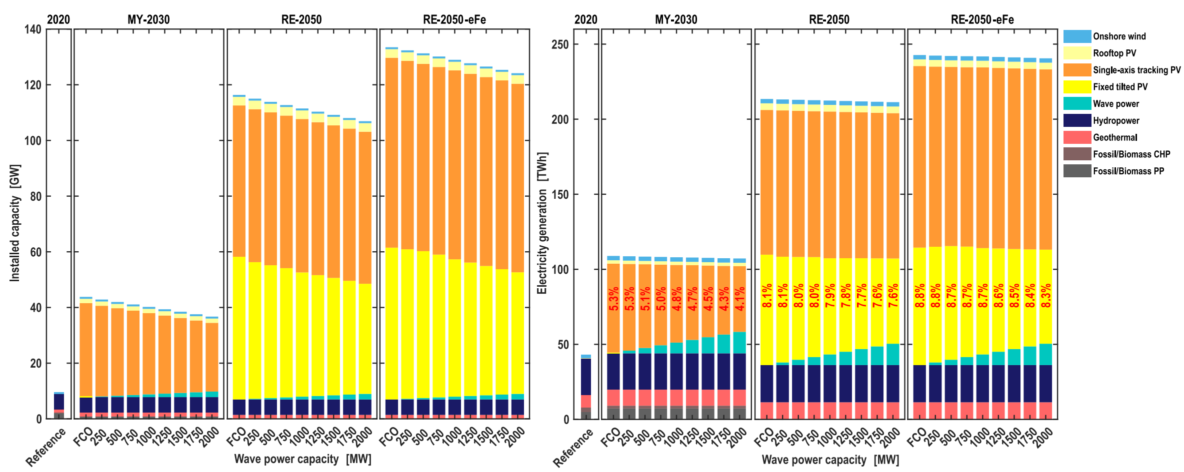

Fig. 3. Installed power capacities and electricity generation in the MY-2030, RE-2050, and RE-2050-eFe scenarios and wave power capacity sub-scenarios. Curtailment (excess electricity) is shown in red as a percentage of the generation potential.

(54.3 GW) and 51% (68.2 GW), respectively. However, the cost optimisation also results in large-scale installation of fixed-tilted solar PV to satisfy the growing demand due to its cost competitiveness, even with a 23% lower yield, compared to single-axis tracking solar PV. Detailed installed capacity numbers according to the scenarios are given in SM Section 3.2.

Additional wind power capacities are not installed in the MY-2030 in the FCO, except for the already built capacities which are assumed to be operating in 2030 as well. Similarly, offshore wind and wave power are not part of a cost-optimal capacity mix, despite having good resources with high capacity factors, across various locations around New Zealand's coastline. This could be due to the aggregation of capacity factors into a single profile for the entire country, which might not capture the region-specific capacity factor profiles. New capacities are entirely based on solar PV, due to its cost-competitive advantage. Similar results are also observed in the RE-2050 and RE-2050-eFe cost-optimised scenarios (FCO).

Other traditional RE technologies in New Zealand such as the hydropower and geothermal are available during decrease in solar PV generation. In 2020, hydropower capacity was 5.4 GW, while geothermal power capacity was about 1.0 GW. As hydropower and geothermal power technologies are modelled in EP, the projected installed capacity for 2030 and 2050 needs to be added exogenously. It was assumed that hydropower will increase by 0.11 GW to a total capacity of 5.5 GW in 2030 and stay constant till 2050 [74]. While for geothermal it was assumed that it increases by 0.38 GW to a capacity of 1.4 GW in 2030 and will largely static till 2050 [74]. The current capacity of fossil fuel-based technologies (2.3 GW) is mainly based on natural gas and coal to support the hydropower-dominated system [75]. Achieving the target of 100% RE in 2030 would require phasing out all of these capacities. It is assumed that 0.5 GW of thermal power generation will phase out the use of coal by 2030 [76] and some of the capacity (0.4 GW) will be used as peaking power plants, which can use different fuels. Thus, it was assumed that fossil capacities will decline to 0.8 GW by 2030 and by 2050 all capacities will be decommissioned. The results of the RE-2050, and RE-2050-eFe scenarios show that balancing multi-fuel power plants are not required, as fixed capacities and storage technologies such as PHES and batteries are enough to balance the peak demand and periods of unavailability of renewables.

New Zealand has excellent wave power resources across its coastline [5]. To explore the role of this potential across the energy system, a wave power converter is introduced as a technology in the modelling [5]. The FCO for the MY-2030, RE-2050, and RE-2050-eFe scenarios, results in no wave power capacity installations, however, interesting findings are made when forcing wave power into the energy system for both scenarios.

- Adding 2 GW of wave power capacity decreases the need for single-axis tracking PV capacity by 8.7 GW_p in MY-2030 and by 0.5 GW in RE-2050-eFe, compared to their respective FCO sub-scenarios.
- Similarly, in the RE-2050 and RE-2050-eFe scenarios, a decrease of almost 11.7 GW_p and 10.8 GW_p is observed in fixed-tilted solar PV, compared to their respective FCO sub-scenarios.
- In the RE-2050 scenario, an increase of 0.2 GW_p is observed in single-axis tracking PV, compared to its FCO sub-scenario.

The drive towards electrification of the demand sectors leads to strong electricity growth, with electricity generation primarily based on solar PV, as shown in Fig. 3. Forcing increasing wave power capacities into the energy system decreases the total electricity generation. At 2 GW of wave power capacity, the 'total electricity generation' decreases by 1.7 TWh compared to the FCO (which has no wave power capacity) in the MY-2030 scenario, while for the RE-2050 and RE-2050-eFe scenarios, it decreases by 2.1 TWh and 2.2 TWh, respectively. A detailed representation of electricity generation according to the technologies for all the scenarios is given in SM Section 3.2.

In the MY-2030 (FCO), the share of solar PV and onshore wind power is 56.9% and 2.7% (relative to demand), while dispatchable hydropower and geothermal have a share of 22.2% and 9.8%, respectively. As the assumption in the growth of installed capacity for hydropower and geothermal is rather small in 2030 and constant thereafter, this results in continuously decreasing relative shares for these technologies, as solar PV satisfies the growing need for electricity supply.

As the wave power capacities are forced, the MY-2030 scenario results in its growing share of total generation from 1.6% (1.9 TWh) at 250 MW capacity to 13.3% (14.3 TWh) at 2000 MW of capacity. Consequently, this results in decreasing shares of single-axis tracking solar PV in the MY-2030 scenario, while in the RE-2050 and RE-2050-eFe, the fixed-tilted share reduces rapidly. Even though the installed capacities of wave power are comparatively smaller, the electricity generation is considerably higher, due to stable resource availability all year round (high capacity factors). Additionally, adding wave power capacities results in lower excess electricity (curtailment) as can be seen in Fig. 3 for the MY-2030, RE-2050, and RE-2050-eFe.

3.2. Energy storage and flexibility

In this study, four storage options were explored: stationary batteries (including utility-scale and prosumer batteries), V2G batteries, PHES, and hydrogen storage for power system balancing. Among the different storage options, stationary batteries, PHES, and hydrogen storage are part of the optimisation, while the available V2G battery capacity is calculated and added as a fixed capacity to the modelling. Fig. 4 gives the details of the optimised storage capacity and discharge in the MY-2030, RE-2050, and RE-2050-eFe scenarios, as well as sub-scenarios with wave power capacities.

As of 2020, there were no major electricity storage capacities online, except the existing hydropower reservoirs and the 0.018 GWh of battery storage capacity. In the MY-2030 scenario as the share of VRE grows to about 59% of the total electricity supply, the need for storage technologies arises. Consequently, 2.2% of the electricity demand is covered by storage technologies in the FCO sub-scenario. Among the storage technologies, hydrogen storage has the highest installed energy capacity of 5.6 $TWh_{H2,LHV}$, followed by PHES (4.6 GWh) and stationary batteries (0.4 GWh).

Adding wave power capacities in the MY-2030 scenario decreases the storage capacity for all the storage technologies involved as seen in Fig. 4. Adding 2 GW of wave power capacity decreases the hydrogen storage capacity by 29%, PHES phases out by adding 1.2 GW of wave power capacity, while stationary battery capacity decreases by 88% by adding 1.8 GW of wave power capacity, compared to the FCO sub-scenario. In the FCO, hydrogen production is coupled with solar PV generation, thus the need for hydrogen storage is the highest. However, as the solar PV capacity decreases with wave power capacity (due to its stable generation profile), so do the hydrogen and other storage technologies. Thus, adding 2.0 GW of wave power capacity results in only 0.16% of the total electricity demand being met through storage technologies.

For the RE-2050 and RE-2050-eFe scenarios, the total storage capacity almost doubles to 11.2 TWh and 13.3 TWh, respectively, in comparison to the MY-2030 FCO scenario (mostly hydrogen as seen in Fig. 4). This large hydrogen storage mainly buffers hydrogen demand as feedstock for industry and transport, rather than re-conversion to electricity. There have been examples of using underground storage for storing hydrogen like in Teeside, UK, (25 GWh storage capacity) and Texas, USA, (~332 GWh) with proven applicability of the approach [77, 78]. However, the scale of storage required will be much larger than the current hydrogen storage sites. A study on the potential of underground hydrogen storage at one of the sites in New Zealand gives a storage capacity of >20 TWh [79]. Thus, New Zealand needs to develop the infrastructure for hydrogen storage matching with the pace of its growth in hydrogen production. PHES and stationary batteries support power balancing as peakers. In both the 2050 FCO scenarios, the need for stationary battery storage increases, a direct consequence of the absence of dispatchable power plants. Thus, in the RE-2050 and RE-2050-eFe scenarios, the installed capacity of stationary batteries is 22.1 GWh and 22.4 GWh, respectively, providing 6-h discharge to cover the evening and night load. There is an additional mid-term storage (PHES) beyond what is built in 2030. In the RE-2050 and RE-2050-eFe scenarios, adding 2.0 GW of wave power capacity reduces.

- Stationary battery capacity by 39.4% to 13.4 GWh, and
- Hydrogen storage capacity by 8.1% to10.2 TWh, compared to the respective FCO scenarios.

The majority of the storage discharge for electricity demand is through stationary and V2G batteries. For the FCO of the MY-2030, RE-2050, and RE-2050-eFe scenarios, the stationary battery discharge is about 10.3% (105 GWh), 56% (7.8 TWh), and 55.8% (7.8 TWh) of the total electricity storage discharge, respectively, while for V2G it is 9% (78 GWh), 38.6% (5.4 TWh), and 38.8% (5.4 TWh) of the total electricity storage discharge. Batteries synergistically complement the large share of solar PV in the generation mix due to their modularity, forming hybrid solar PV-battery systems. In the RE-2050 and RE-2050-eFe scenarios, integrating additional wave power capacities decreases the share of electricity demand met from storage. Detailed numbers are given in SM Section 3.3.

Flexibility is also provided by demand response (flexible demand in EnergyPLAN), smart charging of EVs and electrolysers. A maximum of 1.3 GW of power demand is shifted during the day, depending on peak

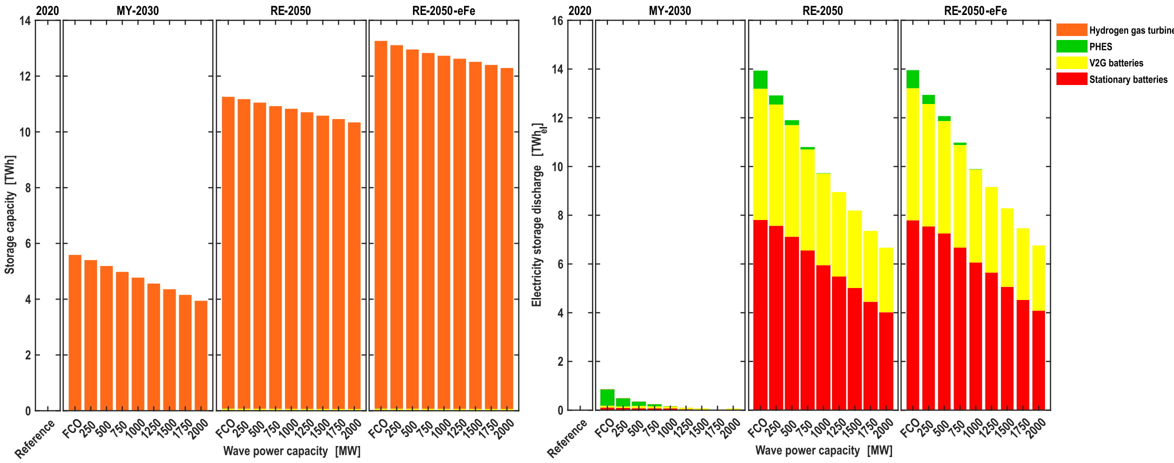

Fig. 4. Installed energy storage capacities (left) and electricity discharge (right) from different storage technologies used in this study in the MY-2030, RE-2050, and RE-2050-eFe scenarios and wave power capacity sub-scenarios.

management. Similarly, smart charging enables EV charging during periods of low demand.

3.3. Cost of the future energy system

Total system costs and levelised costs of electricity are essential indicators to quantify the economic viability of future energy systems. The former needs to be brought down to a yearly horizon (capital recovery factors) while the latter is expressed in terms of the final energy use.

Fig. 5 presents the total annualised cost and the levelised cost of final energy (LCOFE) for the MY-2030, RE-2050, and RE-2050-eFe scenarios across different wave power capacities. As seen from Fig. 5, the total annualised cost of the energy system peaks in the MY-2030 scenario (sub-scenarios with wave power capacity addition). This is higher than the current energy system costs and also higher than fully renewable systems costs (RE-2050/RE-2050-eFe). The annualised system cost in MY-2030 (FCO scenario) is 37.6% higher than the system cost in year 2020. A 100% RE-based system (RE-2050/RE-2050-eFe) results in a total annualised cost of 9.8 b€ and 10.7 b€, respectively, which is similar to 2020. Note that for the e-fuel export case, profits from these exports were not considered (and could further improve the cost metrics).

Based on the cost assumptions used in this study, the total annualised system cost in 2020 was 10.2 b€, of which the majority (6.3 b€) is fossil fuels. A price of 150 €/tonne of CO_{2eq} was part of the assumption to reflect externalities (resulting in 0.8 b€). In other words, the fuel and CO_2 emissions cost account for 70.3% of the total annualised cost. In the MY-2030 (FCO sub-scenario), the total annualised cost does increase drastically, however the share of fuel and CO_2 emission cost reduces to 37.5%. In RE-2050 and RE-2050-eFe (FCO sub-scenario), it further reduces to 6.2% and 6.9%, respectively. Detailed data of individual cost components of the total annualised costs is given in SM Section 3.4.

A similar fundamental cost structure is observed when the LCOFE is compared across the three main scenarios and the sub-scenarios of wave power integration. The LCOFE first increases by 45.3% (to 83.9 €/MWh) in the MY-2030 (FCO sub-scenario), while it decreases by 42.2% in the RE-2050 and 40.3% in RE-2050-eFe, compared to 2030. Even when compared to the current energy system costs of 58 €/MWh (2020), the LCOFE of a 100% RE system is lower at 47.3 €/MWh and 51.9 €/MWh in the RE-2050 and RE-2050-eFe scenarios, respectively. The decline in cost is driven by low-cost solar PV and batteries, complemented by hydropower and geothermal.

4. Discussion

The results show that New Zealand can achieve net-zero emissions by integrating large-scale low-cost renewables. However, achieving 100% RE target requires short- and long-term planning with important decisions regarding the right mix of technologies. The results in 2030 and 2050 might not closely reflect the current status of investment and pace of RE development in the country. The modelling of least cost

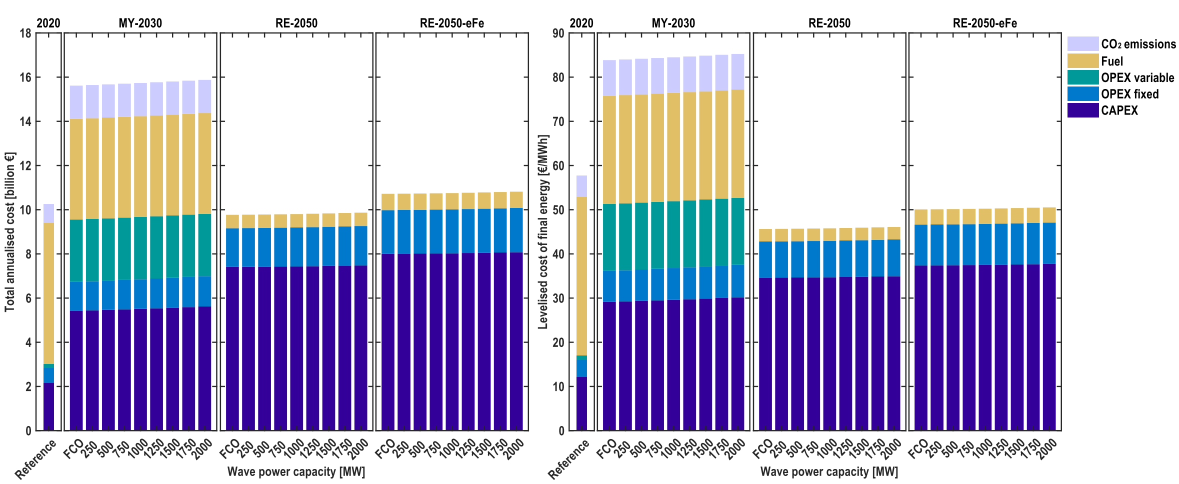

Fig. 5. Total annualised system cost (left) and levelised cost of final energy (right) in 2030 and 2050 for the MY-2030, RE-2050, and RE-2050-eFe scenarios and wave power capacity sub-scenarios.

alternatives based on assumptions and limitations within the study aims to present '**a possible future**' for the energy transition, rather than predicting the exact future.

New Zealand is a developed country with the respective financial and human capital available for building large scale infrastructure. With the ambition to achieve a net-zero energy system, acceleration in reducing fossil fuel usage especially in hard-to-abate sectors such as transport will be required. The role of e-fuels will be important, however, the final share required will be lower compared to a fossil fuels-based system as the majority of the transport sector will be electrified. The interim hydrogen roadmap from the government of New Zealand focusses on the potential demand and future uses of e-hydrogen and one of the key aspect is the use in e-fuel, e-ammonia and e-methanol production [80]. With large scale demand of e-hydrogen expected, understanding the water requirements will be important. Comparing it with the other water uses expected in the future, the share of water required for hydrogen production will be 1.2% of the total water use projected in 2050. According to World Resources Institute, New Zealand is not a water stressed country and will not be till 2080 [81]. Thus, the government seems ambitious enough and recognises the importance of e-fuel development in the future. The modelling of least-cost alternatives provides insights into what the capacity and generation could look like in 2030 and 2050, based on the government's pathway to phase out fossil fuels.

The least cost model shows that integrating wave power in the capacity mix increases the annualised cost of the energy system between 0.9 and 1.7%. Thus, strictly speaking, wave power capacity is not part of an optimal solution but can be considered a near-optimal alternative. As pointed out by Neumann and Brown [82,83], for Europe, a slight cost deviation from the optimal solution offers a range of technologically diverse options for policymakers, keeping in mind the uncertainties in cost and social acceptance between technologies, among many other uncertainties. Similarly, Prina et al. [84] emphasised the need for a diverse energy system for Italy, with different clusters of optimal and sub-optimal solutions. Thus, wave power could play a key role in countries with excellent resource potential, even with a slight increase in energy system costs, while increasing the diversity of the energy system.

Due to its widespread availability and low cost, solar PV is the core of the energy transition, also for New Zealand. In a cost optimisation, single-axis tracking solar PV is found to be the most attractive option in 2030 and complemented by fixed-tilted PV in 2050. This reflects the current industry strategies which aim to increase the current 30% market share of single-axis tracking to 40% by 2030 [85,86]. From a system perspective, this means that the higher investment costs for single-axis tracking are more than compensated by higher energy yields, less battery storage demand, and better electrolyser utilisation. To install the maximum capacity of utility-scale solar PV and onshore wind power, New Zealand would require 4% of the unused area (not accounting for the area occupied by lakes, rivers, agriculture, shrubs, forests, cropland and urban areas). It should be noted that solar PV can also be installed on lakes as floating PV systems [87] and on agricultural land in the form of agrivoltaics [88] so that the total area required will not be a constraint to the development of the capacity, and similarly to rooftop PV, such systems can use zero impact areas [89].

The current electricity generation in New Zealand has a major share of hydropower, however, in a 100% RE-based system the share reduces considerably, while all existing capacities remain in use. Nonetheless, the impact of climate change on rainfall and availability of hydropower cannot be overlooked [90]. Specifically, the representation of hydropower generation in EnergyPLAN, which is simplistic based on availability of water from the storage, does not always produce the accurate output of electricity by assuming the same generation profile even in 2050. Thus, a dry year would have an impact on the operation of the power system by reducing electricity generation. This will result in additional generation and storage capacity requirement to balance the power system. Thus, incase of dry year, wave power could play an integral role, due to its high FLH. However, with high potential available all year round, the impact of wave power on an energy system will not be limited to just dry years, but will add diversity to the generation technology portfolio. The results show that adding 2 GW of wave power capacity increases the diversity of supply options with a maximum cost increase of 1.7% for the 2030 scenario. According to Satymov et al. [5], wave power could become cost-competitive to offshore wind power after 2030 in most locations, especially in places with good wave resources. This is in line with the results, as the cost increase is less than 1% in the 2050 scenarios. The total system costs are relatively insensitive against the different capacities of wave power across the scenarios. This is particularly noteworthy in a one-node model used in this research because it inherently underestimates the need for balancing technologies (it assumes unlimited, free transmission). Deploying wave power technology would likely reduce the need for other generation and balancing technologies.

Small island nations could transition to meet their climate targets in sectors that are hard to electrify by importing sustainable fuels from larger countries capable of producing and exporting them more cheaply [11]. The results show that New Zealand could export e-fuels to the Pacific Islands with a total annual energy system cost increase of 9.7% in the FCO and 9.6% when adding 2 GW of wave power capacity, compared to the RE-2050 scenario. However, it should be noted that the revenues from exporting e-fuels are not considered in this study. Thus, these revenues would create a profitable business case for exporting countries around the globe, like the current fossil fuel market. Exporting e-fuels would require additional infrastructure for e-hydrogen and e-fuels production, however, with a modest 10% increase in generation capacities. A similar study [91] on Greenland as a potential e-fuel exporting hub was done using EnergyPLAN, highlighting the huge RE potential to enable e-fuel exports. It may be probable that the Pacific islands explore other partner countries for importing e-fuels, which might be even cheaper than New Zealand, such as Australia [11]. Even with lower e-fuel production costs in Australia, the Pacific islands could diversify the portfolio of exporter countries for energy security and supply chain issues.

In terms of costs, the LCOFE in an energy system based on large shares of RE is expected to decrease compared to the current energy system, as shown on a global scale by Bogdanov et al. [92]. For the specific case of New Zealand, even with electricity demand expected to grow from 40 TWh in 2020 to 103 TWh in 2030 to 196 TWh in the RE-2050 and 222 TWh in RE-2050-eFe scenarios, the LCOFE is lower than for the current energy system. A decrease in Capex of RE technologies with no associated CO_2 emissions and fuel costs leads to an overall decline in annualised costs for future scenarios. Currently, the Capex and Opex of wave power technologies are expensive even at the best sites in the world. However, research and development with technological improvements and increasing capacity installations globally will drive the cost down within the next few years. According to Satymov et al. [5], the best sites around the world will be able to achieve an LCOE of below 30 €/MWh in 2050, which might be comparable or even cheaper than many onshore technologies.

5. Outlook and limitations

While this analysis provides a forward-looking perspective, it has certain limitations. Predicting the future is inherently uncertain, and none of the pathways outlined here should be seen as the optimal or preferred route. The scenarios presented here are based on the data and assumptions that might inherently change overtime. The primary goal of this study was to show different scenarios for 2030 and 2050 to illustrate the magnitude of the changes needed and the potential choices and trade-offs that New Zealand may face. Further limitations of the modelling and the results are given below.

First, the model used in the present study is a single-zone (single-node), which means it does not capture the transmission system. This is especially important when wave power generation is concerned, as multiple wave power sites can be grid-integrated through a transmission system [93]. One way of looking at this is that the transmission system can be built out quickly enough to not limit the spatial mismatch between supply and demand. Often, this is a strong assumption, and thus, as the next steps for future research, it is recommended to understand the spatial scale by modelling the country in different zones, capturing local generation potentials and including transmission interconnections to understand bottlenecks. Multi-nodal analysis will also capture the local RE resource potentials as some regions will have better potential than others.

Second, EP-ALISON-LUT added a level of complexity to the existing EP modelling tool. However, future analyses using an energy system modelling tool should add more complexity encompassing a broader social, economic and environmental context [94], rather than focusing on simplified technical and economic approach. As such, there is a clear need for a synergistic outlook of the energy system transition. However, there will always be a trade-off between the level of granularity and complexity required in an energy transition analysis to the computational, data and time intensiveness of these analysis. Thus, some of the assumptions in this study are simplified and may not reflect the real situation. While pace and growth in RE and storage installations is observed, a faster transition will be required to achieve the goals by 2050, especially focusing on hydrogen storage infrastructure.

Third, simplistic modelling of some of the technologies results in impacts of these technologies on oversimplification of scenario pathways, which may not reflect reality. For example, a simplistic approach in modelling hydropower plants in EnergyPLAN adds limitations and the results might not represent real operation of these plants. Thus, adding complexity to the modelling of hydropower plants will enable a detailed analysis of flexibility and storage technologies required.

Fourth, the production of e-fuels was modelled by indirectly translating them into an equivalent electricity demand. Other integrated energy system planning tools, such as LUT-ESTM [95,96], PyPSA [97,98], or REMix [99], can capture the much more complex dynamics between energy sectors, including readily available flexibility options, which we propose as future research.

Fifth, the study does not look into the life-cycle analysis of individual technologies or the entire energy system. However, we take into account the life-cycle cost accounting as part of the annualised cost of the energy system.

Finally, there are many co-benefits of defossilisation, including job creation, reducing greenhouse gas and other harmful emissions, energy security, and business opportunities through e-fuel trading that have not been quantified in this study. Further work quantifying these co-benefits would provide valuable insights.

6. Conclusions

Scenarios for a 100% renewable energy system in New Zealand for all energy sectors have been modelled. This includes the role of e-hydrogen and e-fuels, especially in those hard-to-abate sectors, as well as their exports to the Pacific Islands. Two milestone years, 2030 and 2050, next to the base case of 2020 were studied. Additionally, the techno-economic impact of wave power technology has been evaluated.

The key results are:

- Within the cost-optimised energy system, there is a limited role for wave power due to its higher investment cost compared to solar photovoltaics and wind power. However, integrating different capacities of wave power can lead to near-optimal solutions with only slight cost deviations, while providing technologically diverse energy system design options. Additionally, the integration of wave power capacities significantly reduces the need for installed generation and storage capacities (given its higher capacity factor and anti-correlated generation profile).
- New Zealand, with its vast potential of renewable energy resources, including wave power, is poised to become a key player in the Oceania region for exporting e-fuels to Pacific Island nations. While this will require further infrastructure development within the country, the additional 10% increase in capacity and 3.4% rise in the levelised cost of final energy remain modest. Nevertheless, this presents a significant opportunity for boosting New Zealand's trade balance and jobs.
- To meet the growing electricity demand from about 40 TWh in 2020, projected to roughly 100 TWh in 2030 and 200 TWh in 2050, the electricity system needs to be built out very quickly from roughly 10 GW capacity today to 40 GW in 2030 and over 100 GW in 2050. While the specific numbers depend on the scenarios, they all agree on the order of magnitude.
- Electricity storage capacities, coming mainly from stationary batteries and vehicle-to-grid capabilities, need to be ramped up to 3 GWh in 2030 and 71 GWh in 2050, of which New Zealand already has 4200 GWh in hydropower plants, which also act as storage. However, a single-nodal tool likely overestimates these numbers, while the use of a single weather-year might be underestimating the need for inter-annual storage.
- In terms of costs, the levelised costs of final energy would increase from 60 €/MWh in the year 2020 to 84 €/MWh in 2030, to then drop again to roughly 50 €/MWh in 2050 as technologies become cheaper and fossil fuels are phased out. The costs are similar across scenarios. We note our modelling did not capture the exact storage operation of the existing 5.5 GW of hydropower reservoirs, likely slightly overestimating the costs.

The transition towards its net-zero goal by 2050 would require massive ramping up of capacities and storage infrastructure. However, the biggest challenge is the speed required for building the infrastructure and the right policy framework. New Zealand should look beyond hydropower and geothermal and explore the enormous potential of solar photovoltaics, wind power and wave power. The export of e-fuels can create business opportunities for New Zealand, and it could be worthwhile to exploit this potential.

CRediT authorship contribution statement

Ashish Gulagi: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Resources, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Dominik Keiner:** Software, Methodology, Investigation. **Rafaella Canessa:** Writing – original draft, Validation, Resources. **Rasul Satymov:** Resources, Data curation. **Mai ElSayed:** Resources, Data curation. **Rebecca Peer:** Writing – review & editing, Writing – original draft, Validation, Conceptualization. **Jannik Haas:** Writing – review & editing, Writing – original draft, Validation, Supervision, Conceptualization. **Christian Breyer:** Writing – review & editing, Writing – original draft, Validation, Supervision, Project administration, Investigation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.energy.2025.134878.

Data availability

Data will be made available on request.

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