Highlights

Assessment of medium and long term scenarios for the electrical autonomy in island territories: the Reunion Island case study

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- A set of scenarios for 2030 and 2050 are generated
- More expensive scenarios consume less water and emit fewer greenhouse gases
- Electrical facilities can take up to 3% of the island's surface area in the long term
- Up to 2GWh of storage could be needed to reach the island's electrical autonomy

Assessment of medium and long term scenarios for the electrical autonomy in island territories: the Reunion Island case study

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Abstract

Island territories, due to their specific energy context, are at the forefront of energy transition studies with the aim of achieving energy autonomy. This is the case of Reunion Island, where the electricity mix is currently 70 % carbon-based and where imports provide 80 % of the energy consumption. In this context, this article assesses the facilities to install in the medium and long term to progressively reduce energy imports. Several scenarios of installed power generation capacities have been studied for 2030 and 2050, associated with two scenarios for electricity consumption. Simulations are performed according these scenarios in order to define the electricity mix and the investments in new batteries and in the electricity transmission network reinforcement. For 2030, results show that a reduction in consumption compared with the trend could enable reduce costs and environmental impacts. For 2050, investments in new electricity generation technologies are essential to meet the needs of a 100 % electrified vehicle fleet. If the overall consumption does not follow an energy demand management plan, all the energy sources on the island will have to be exploited to their maximum.

Abbreviations: BAU, Business-as-usual; DSO, Distribution system Operator; EE, Energy efficiency; GHG, Greenhouse gas; IPCC, Intergovernmental panel on climate change; OTEC, Ocean thermal energy conversion; PV, Photovoltaics; SWOT, Strengths - weaknesses - opportunities - threats

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The energy transition will also require large storage facilities and little reinforcement in the current electricity high voltage network.

Keywords: Reunion Island, electrical autonomy, energy transition, energy management in isolated territories, renewable energy

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Nomenclature

Parameters

n	Substations
s	Storage units and generators at a substation
l	High voltage lines
t	Timesteps
$d_{n,t}$	Hourly electrical demand at a substation (MW)
$\underline{g}_{n,s}$	Upper bound of nominal power of electrical generators
$c_{n,s}$	Capital cost of storage units or generators (€/MWh)
c_l	Capital cost of high voltage lines (€/MVA)
$o_{n,s,t}$	Marginal cost for storage units or generators (€/MWh)
dr	Discount rate
lf	Lifetime of a technology (years)
K_{nl}	Incidence matrix of a high voltage line at a substation
$\eta_{n,s}$	Standing losses of a storage unit
$MaxProd$	Maximum production of a sector over a year (MWh)

Variables

$\bar{g}_{n,s}$	Nominal power of electrical generators (MW)
$\bar{e}_{n,s}$	Storage nominal energy (MWh)
$h_{n,s,t}$	Hourly dispatch of a storage unit (MW)
$e_{n,s,t}$	Hourly energy stored in a storage unit (MWh)
$g_{n,s,t}$	Hourly dispatch of a generator (MW)
F_l	High voltage line capacity (MVA)
$f_{l,t}$	Hourly power flow (MW)

1. Introduction

The world is facing unprecedented climate change and the need to move away from fossil fuels is more relevant than ever. With the Intergovernmental Panel on Climate Change (IPCC) predicting that this could increase the risk of conflict [1], the need to reduce this dependence involving global energy trade is even greater. In this context, islands face a particular energy situation: they are weakly or not connected to larger grids on the continents, weather conditions are sometimes extreme, intermittent energy sources are locally important, and the transport and distribution of energy can be difficult to set up. These regions are therefore highly dependent on imported resources, in particular fossil fuels, used for both electricity production and transport, and their energy transition can be complicated to implement. In France, the transition of these specific territories is planned since 2015. Since then, the law on Energy Transition for Green Growth sets the objective of energy autonomy in 2030 for the french Overseas Departments and Regions and in 2050 for Corsica. Located in the south-west of the Indian Ocean, between the islands of Madagascar and Mauritius, Reunion Island is the most populated of the five French overseas departments. In 2020, more than 857 000 inhabitants lived in this 2 512 km^2 island [2]. Regarding the development of its energy transition, the territory has several strengths and opportunities, but also weaknesses and threats. These are summarized in Appendix A, through a SWOT analysis (Strengths - Weaknesses - Opportunities - Threats). The present paper focuses on the energy transition of Reunion Island. As there is a certain delay in achieving the objective of energy autonomy mentioned above, what futures are currently possible for the island's electricity system, and at what cost?

Common subject of study for energetic studies, islands from many different countries are represented in the literature. Spain [3, 4], Denmark [5], Norway [6], Turkey [7], France [8], China [9], United States [10], Greece [11, 12] or Portugal [13] are among them. The objectives of a 100 % renewable mix or energy autonomy are predominant in the studies. However, the methods used to achieve them differ: optimisation tools for future investments, evaluations of hydrogen integration, simulations of different configurations or specific studies on electric vehicles. Indeed, each island is unique and does not start from the same point: while the Faroe islands were 41 % renewable in 2019 [5], all electricity was generated by fuel for the island of Saint-Barthélemy [14]. Other more global studies present tools to assess the decarbonisation of islands. They investigate the replicability of the proposed means to several islands. In [15], only five buildings are modelled, while in [16] and [17], eight and four European islands respectively are compared. The main limitation of these studies lies in the non-openness of the models used and the impossibility of reproducing the methodology followed for another case study.

Regarding Reunion Island more precisely, several regional reports are regularly published, on specific sectors or on the island's energy development objectives. The PETREL report [18], from 2009, defines two scenarios for the evolution of the island's energy situation for 2020 and 2030: a business-as-usual one (BAU) and another one called STARTER, reflecting the territory's objective of energy autonomy for 2030. Similarly, the SRCAE (regional air climate energy scheme, 2013) [19] contains forecasts of electricity generation and installed capacity. The island can also rely on its Multiannual Energy Programmes [20] (PPE). This tool for steering energy policy is developed jointly with national and regional authorities. The current one covers the period 2023 - 2028 and proposes scenarios for consumption, production and the evolution of the transport sector. All are designed to achieve the objectives of the 2015 law, with an intermediate objective of 99 % of renewable energy in the electricity mix by 2028. A report of the French Agency for Ecological Transition (ADEME) examines possible ways to achieve the objectives of the law [21]. Lastly, the EDF-SEI report [22] presents two scenarios of electricity consumption and production for 2023, 2028 and 2033. EDF-SEI is the Distribution System Operator (DSO) and the division of the leading national electricity producer and supplier, operating exclusively in non-interconnected areas. Four articles describe the energy transition of Reunion Island [23, 24, 25, 26], all based on the same modeling of the island, but exploiting different aspects and presenting different results. The main limitation of these documents is that they do not take into account past predictions and do not propose long term planning. Indeed, they only present medium term energy system planning, i.e. up to 2030. As the global energy transition is lagging behind, the long term, i.e. 2050, is also taken into account in the present study.

The other contributions of the present paper are first the comparison of existing energy studies of Reunion Island. Based on this, new scenarios for the evolution of the energy context by 2030 are defined, taking into account the current situation of the island. A methodology for the modelling, simulation and techno-economic optimisation of these scenarios is presented, summarized in Figure 1. The aim of the tools developed is to be used for any island case study in the future.

The present paper provides a common tool to better initiate the energy transition of non-interconnected areas, as well as guidance for the energy transition of Reunion Island in the long term. It is organised as follows:

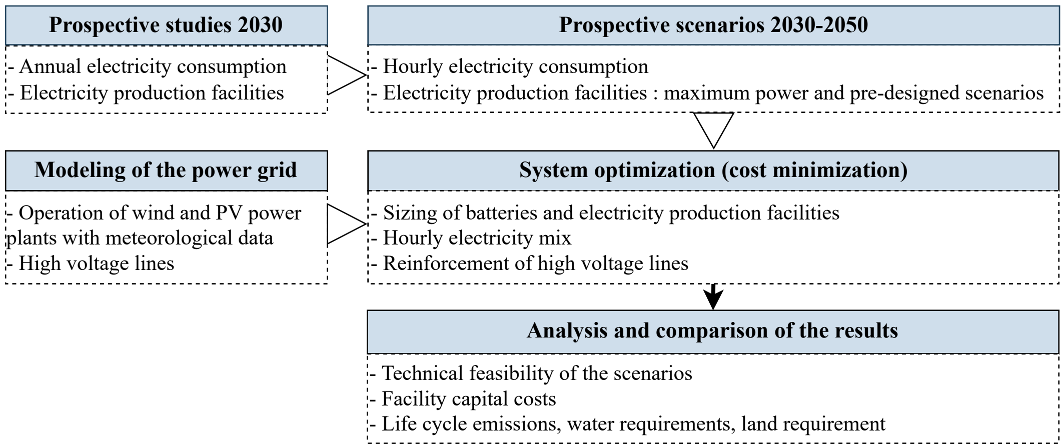


Figure 1: Flowchart of the proposed methodology.

after the introduction section, section 2 presents different energy situations on the island. Past forecasts for 2020, current situation and forecasts for 2030 from the literature are detailed. Section 3 presents the methodology for modelling, simulating and optimising the new scenarios. These are then compared from a technical, economical and environmental point of view in Section 4. The article ends with a discussion and a conclusion in sections 5 and 6.

2. Reunion Island energy planning comparison

To implement the energy transition of a territory, objectives must be set and medium and long term action plans must be adopted. These actions include investments in local electricity generation and targets for primary energy consumption reduction. These two points are examined in this section, where scenarios for the evolution of electricity consumption and installed power generation capacities are compared. First, a focus on the past forecasts of Reunion Island for 2020 is made, followed by a comparison with the current situation of the island. Then, studies proposing medium-term forecasts for the electricity mix of Reunion Island are compared.

2.1. Past forecasts and current situation

Forecasts of the evolution of the energy situation of Reunion Island have already been made in the past. In particular, two reports presented targets

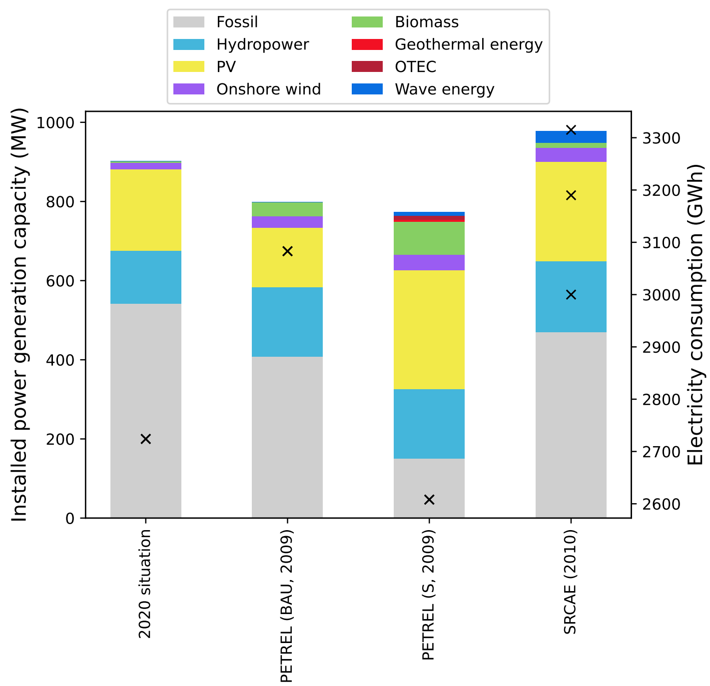


Figure 2: Comparison of the 2020 forecasts to reality. Crosses correspond to the consumption forecasts.

for 2020, which can be compared today and allow to assess whether their forecasts were correct [18, 19]. Both reports contain forecasts of electricity generation and installed capacity for 2020, neither of which has yet been reached in 2022. The comparison of installed power generation capacity and electricity consumption can be found in Figure 2. The "fossil" category includes installations using exclusively fossil fuels but also installations using a mix of fossil fuels and biomass resources. If electricity consumption forecasts rather well framed the reality, almost every installed power generation capacity has been overestimated. The law on Energy Transition for Green Growth from 2015 presents an intermediate target of 50 % renewable energy by 2020. This target was not reached for electricity production, as 31.3 % was from renewables, nor for primary energy consumption, as 13 % was from renewables.

As shown in Figure 2, power generation is currently mainly based on fossil fuels. The map of the installed capacity can be seen in Figure 3a.

The electricity network can rely on several thermal units; among them, two coal and bagasse (the fibrous residue of sugarcane crushing) power plants for a total of 210 MW are used for base loads. Work has started on converting these two power plants to biomass. The bagasse part will be kept, and coal will be replaced by local biomass resources and pellets imported from North America. Another plant may be converted to liquid biomass, mainly rapeseed oil, imported from Europe: the diesel plant of 211 MW installed in the north-west of the island. Three combustion turbines, for a total of 121 MW, are also installed, as well as 133 MW of hydroelectricity, 4.4 MW of biogas plants, 16.5 MW of wind turbines and 200 MW of photovoltaic systems (PV).

In Reunion Island, the electricity grid is operated by EDF-SEI. 25 substations are located on the island, linked together by 500 km of 63 kV lines (see Figure 3b). These substations are linked to 3 500 km of 15 kV lines, mainly underground. Since 2019, the maximum penetration rate of intermittent renewables on the grid has been set to 35 % [20].

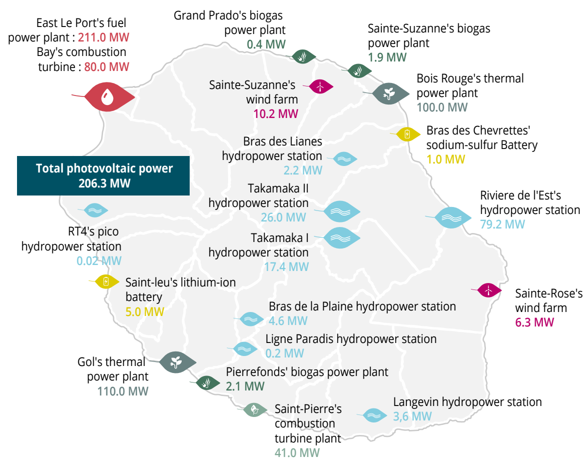
2.2. Comparison of scenarios

New predictions for 2030 have been made since the previous forecasts presented. Several articles and reports follow the law on Energy Transition from 2015 and try to estimate the evolution of the energy mix of Reunion Island by 2030.

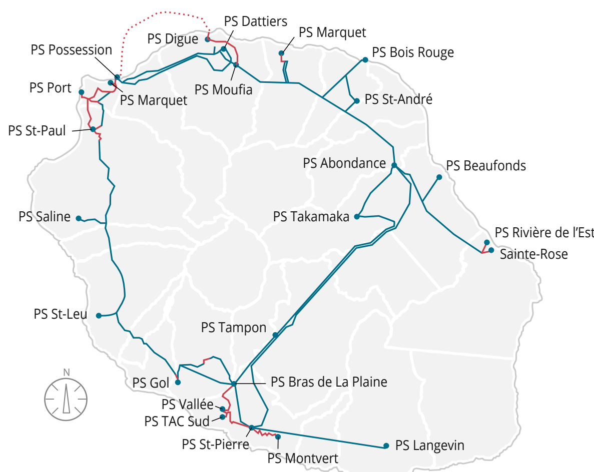
2.2.1. Installed power generation capacity

First, the different existing scenarios of installed power generation capacity for 2030 are compared. This comparison will be used as a basis for defining new scenarios for the same period and for the longer term (2050). The different scenarios of installed electricity generation capacity compared can be found in Table B.3. The results of the comparison are shown in Figure 4. Two articles [23, 25] present scenarios made up of a mix of those of a third one [26], but have not been plotted due to a lack of data on biomass potential. Another article [28] details the results of one of the ADEME report's scenarios [21] and thus has not been plotted.

Overall, the scenarios offer very different forecasts. While some scenarios indicate zero fossil power for 2030, others maintain the installations, which have not yet reached the end of their life, but specify that they will no longer be used by the targeted date. Few scenarios maintain the use of fossil resources in 2030, as investments in new coal power plants may be more economically attractive. Regarding biomass energy, the data depend on the conversion of thermal power plants, taken into account or not in the forecasts.



(a)



(b)

Figure 3: (a) Map of installed capacity in 2020 [2].; (b) Map of the high voltage electricity network [27]. Red lines are underground and submarine lines.

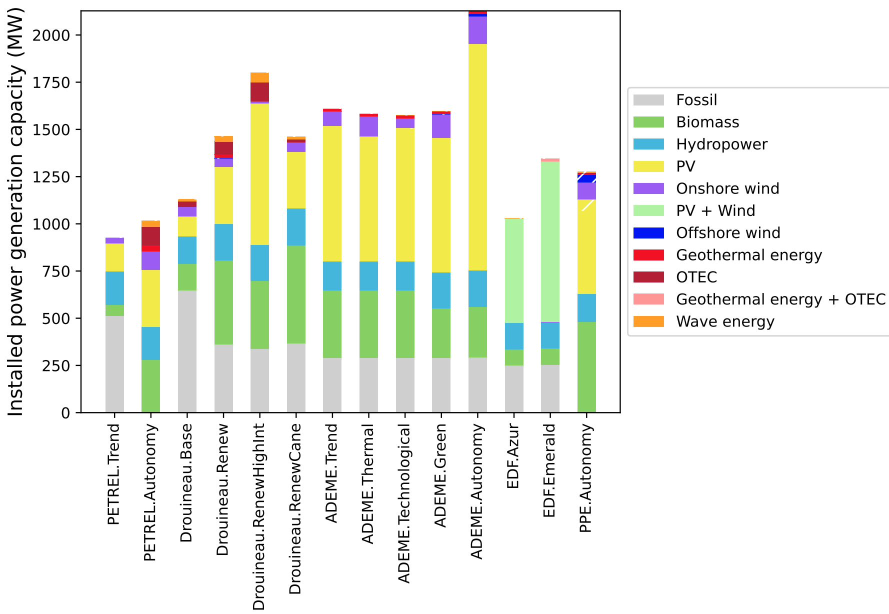


Figure 4: Comparison of scenarios for installed power generation capacity in 2030. Hatching corresponds to the high ranges of *PPE.Autonomy*.

The scenarios using the least biomass are those that aim for energy autonomy in 2030: to supply large power plants, the resource will necessarily have to be imported. Finally, the forecasts bet on energies not yet exploited on the island, such as offshore wind, wave energy, ocean thermal energy conversion (OTEC) or geothermal energy.

2.2.2. Electricity consumption

The other area that contains several scenarios for 2030 is electricity consumption. Most of the reports and articles reviewed propose two scenarios for this horizon, a trend scenario and an energy-efficiency (EE) one. Overall, the consumption targets for the island are of the same order of magnitude, as shown in Figure 5.

Finally, the last area studied is the consumption of electrical vehicles. In 2019, the road sector alone accounted for 34 % of the consumption of imported fossil fuels in Reunion Island. Within this sector, private cars represent 77 % of vehicles, justifying the need for their transition. Two reports make forecasts on the electrification of the private vehicle fleet and the resulting additional electricity consumption [22, 21]. If the percentage of the

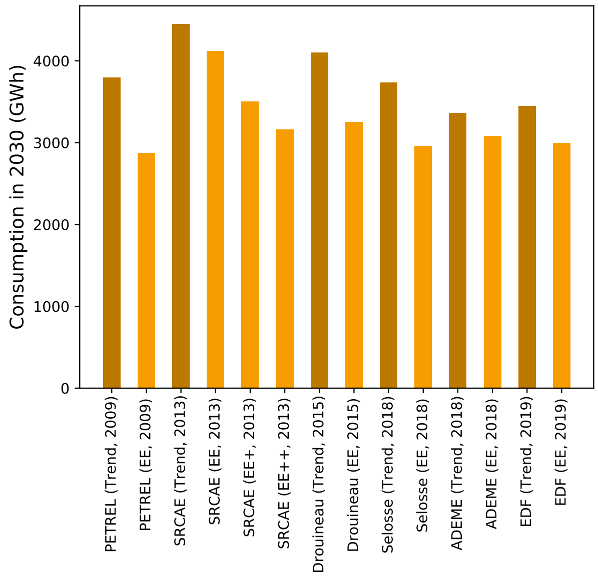


Figure 5: Comparison of the consumption scenarios.

fleet of individual vehicles electrified by 2030 can be different, the resulting power consumption is consistent between the two reports.

3. Methodology

After having compared various data on Reunion Island's electricity supply by 2030, new energy scenarios will be defined; for the electricity production facilities and for the electricity consumption, for both 2030 and 2050. Indeed, after noticing the delay in relation to the forecasts for 2020, it seems difficult today to engage a complete transition of the local energy system to reach energy autonomy by 2030. In this work, autonomy will be targeted for 2050. First, the electricity consumption scenarios will be presented. The system will then be modelled and optimised to meet the introduced electricity demand, in order to propose optimal electricity production scenarios. These optimums will then be compared to other pre-designed scenarios, taking into account different energy policy choices in the coming years for Reunion Island.

3.1. Modeling of electricity consumption

The modelled electricity scenarios will be the basis for our optimisation. Indeed, the first objective for the modelling of an electrical network is to be able to satisfy the demand at each time step.

For 2030, the choice was made to use electricity consumption scenarios from the ADEME report [21]: a demand of 3 080 GWh for the whole island with a **EE** scenario, and a demand of 3 360 GWh with a **Trend** scenario. The first scenario assumes a more proactive approach to managing energy demand, for example through energy efficiency measures, and a more optimistic view of the capacity to disseminate the associated technologies. The same objectives were kept for 2050, with the assumption of an increase in demand due to an increase of population and an electrification of uses compensated by a more advanced demand-side management over the years. As the island's electrical network is modelled by its various substations, the data introduced must be distributed there. The assumption of similar growth among all substations in the long run is made. Island hourly generation data are used, with typical profiles for tertiary buildings and primary residence data for the residential sector, in conjunction with occupancy and appliance usage data [29].

In parallel, consumption data of electric vehicles are required. Annual data for the whole island can be obtained, based on the percentage of the individual vehicle fleet electrified [21, 22]. To define an hourly load profile for a typical day, EDF-SEI report [22] is used. In it, two daily profiles of electric vehicle consumption in 2033 in Reunion Island are defined, the first for a fleet that can be driven at 40 % and the second at 80 %. A connection with the demography of the island is used for the distribution of the data; the assumption of a majority of home charging is made, and the data are distributed to the substations according to the number of inhabitants of the island's municipalities. For 2030, the impact of the electrification of the private vehicle fleet has not been taken into account. For 2050, a fleet electrified at 100 % has been considered, of which 80 % can be driven. The different load profiles can be seen on Figure 6.

3.2. Modeling of electricity production

Together with the electrical demand, electrical production and storage data are affiliated to each substation, which are connected to each other by high voltage transmission lines.

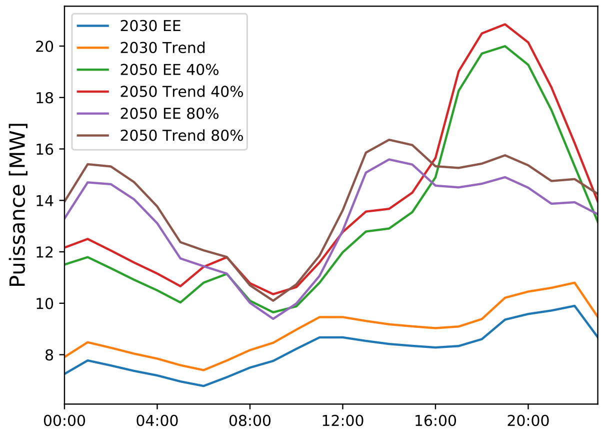


Figure 6: Load on one of the substations on a weekday, depending on the simulated consumption scenario. The 2050 scenarios both have a 100 % electrified private vehicle fleet, of which 40 % or 80 % can be driven.

The power generation capacity installed at each substation will be optimised in the first instance. To do this, a maximum power is defined for each sector for each modelled horizon. For 2030, the PPE [20] forecasts have been taken for all the existing energy sectors on the island, except for PV: for this sector, the average of the forecasts of the compared literature scenarios is taken as the upper bound. For 2050, the existing sectors are maximised by their potential [21] as defined in the literature. Three new sectors are also considered for this horizon: offshore wind, geothermal and OTEC. Their installed capacity is maximised respectively by the high range given by the PPE for 2028 [20], the only potential evaluated and half of the potential defined [21]. The distribution of installed capacity at the different substations is carried out using data from [21]. The data for 2030 were distributed according to the capacity of each substation. For 2050, no restrictions were considered.

The resulting scenarios will thus be economically optimal and technically feasible. They will then be compared with seven pre-designed scenarios, three for 2030 and four for 2050, detailed next, which describe likely futures depending on policy decisions taken in the coming years. In particular, having pre-defined power generation scenarios allows other features of the power system to be studied with reduced computation time. The resulting electricity mix of all the scenarios will be composed during the simulation and optimisation of the system. Regarding the scenarios for 2030, only electricity production technologies currently used on the island have been developed. The current situation of the island is considered and is taken as a basis of the three scenarios. Imports of fossil or renewable resources are considered, in line with the projects currently developed on the island.

- The **Trend** scenario follows the guidelines of the PPE [20]. This scenario is named as such because the decisions taken in the energy sector in the coming years will most likely be based on this report. PV and wind installations increase significantly and small hydroelectric projects are being carried out. Current coal - bagasse plants are converted to 100 % bagasse (almost 70 % of the installed capacity will be supplied by imports) as well as current diesel engines to liquid biomass (almost all supplied by imports). The bioethanol combustion turbine is maintained, as well as current biogas plants. Some biomass projects are considered, such as new biogas plants or projects for the recovery of refuse-derived fuel.

- In the **80 to 90 % renewable** scenario, only the current coal - bagasse plants are converted to 100 % bagasse and the diesel engines keep working with heavy fuel oil (211 MW). Indeed, work on the conversion of the first plants has already started, but for the second plant, a public consultation on the conversion project has just been completed. PV installations are developed according to the average of the compared scenarios, as well as hydropower. The average of the lowest values of the compared scenarios is retained for wind power: the installed capacity of the sector has not increased since 2008, but repowering projects are currently being carried out. The additional biomass and biogas projects of the previous scenario are maintained. This scenario considers a medium-term future where the planned energy transition has been delayed and thermal power is still present on the island.

- Finally, the **100 % renewable** scenario follows the same pattern as the previous scenario, except that the current diesel engines are converted to liquid biomass by 2030, as planned by the Region. This scenario proposes the same renewable electricity mix target as the Trend scenario. The situation is however different because data from the comparison of studies in the literature were used.

For the 2050 scenarios, the three new technologies considered above for power sizing will be integrated, with their upper limits introduced as installed power. The whole power generation system will be taken from scratch and no imports of fossil or renewable resources are considered.

- The **Base** scenario develops OTEC and geothermal energy as new base production energies. The maximum of the potential [21] for photovoltaic and biomass facilities is considered. Regarding the hydraulic capacity, the one used in the last scenario of the ADEME report is chosen. Finally, because of the local weaknesses of the sector, the wind capacity is only doubled compared to the previous 80 - 90 and 100 % renewable scenarios for 2030. This also corresponds to the average of the highest values of the compared scenarios. This scenario allows to assess a situation where base production is largely developed.

- In the **Intermittent** scenario, offshore wind is the only new production sector developed. PV, hydropower and biomass capacities are the same as the previous scenario. Only wind power is revised upwards, taking the highest value possible from the scenarios from the literature. This scenario allows to assess a situation where intermittent power generation is predominant.

- The **Decarbonised** scenario is a mix of the two previous scenarios, with the end of the biomass sector (thermal power plants, incinerators, combustion turbines), excluding bioenergy (electricity production by methanization). The installed capacities of geothermal, OTEC and PV are the same as in the first scenario and those of onshore and offshore wind are the same as in the second scenario. Hydraulics takes the value of the maximum potential [21], as well as biogas. Indeed, every possible facility will be required in order to compensate the end of the biomass sector. Today, the island's two coal - bagasse power stations are being converted to 100 % biomass. However, local reserves are not sufficient to ensure equivalent electricity production, and imports are planned. By aiming for local electricity production in 2050, biomass production will have to be reduced. Moreover, it is possible that sugar cane cultivation, which produces bagasse, will be abandoned in the future to make way for other food crops. Indeed, the island has to import many food resources; in 2021, more than 118,000 tonnes of agricultural products were imported into Reunion Island [30]. This scenario therefore assesses the impacts of a long-term situation in which the biomass sector would only be represented by biogas plants in Reunion Island.

- Finally, the **Combined** scenario is also a mix of the first two scenarios, and is made up of all the upper bounds of the production sectors defined in the power sizing part. The objective of this scenario is to evaluate the impacts of an energy system where all local energies are exploited to their maximum.

The summary of installed capacities by scenario can be seen on Figure 7.

3.3. Optimisation problem

In order to assess the technical feasibility of the previously introduced scenarios, size the optimal scenarios and optimise the electricity mix in each case, the operation of the Reunion Island electrical system is simulated for 2030 and 2050 with an economic optimisation.

The following notations are adopted: n for the substations, l for the high voltage lines, t for the timesteps (every hour of year 2050) and s for the different generators and batteries at a substation. Input data are: the hourly electrical demand ($d_{n,t}$ in MW), the nominal powers of the electrical generators if not optimised ($\bar{g}_{n,s}$ in MW) or their upper bound ($\underline{g}_{n,s}$ in MW) and meteorological data (wind, temperature, radiation) for the operation of the PV and wind facilities.

The optimization variables are: the nominal energy of the batteries ($\bar{e}_{n,s}$ in MWh), their hourly dispatch and stored energy ($h_{n,s,t}$ in MW and $e_{n,s,t}$ in MWh), as well as the hourly operation of the power generation technologies ($g_{n,s,t}$ in MW) and the potential reinforcements of the high voltage lines (F_l in MVA). The hourly operation of intermittent power generation technologies is not optimized; all the possible energy produced is recovered. The nominal powers of the electrical generators ($\bar{g}_{n,s}$ in MW) are optimization variables in the case of the power sizing part of the study.

These variables are subject to a Mixed Integer Linear Programming (MILP) algorithm, minimizing the investment costs on batteries ($c_{n,s}$), power lines (c_l) and generators if required ($c_{n,s}$), as well as the operating costs of generators and batteries ($o_{n,s,t}$). The objective function is expressed in Eq. (1):

$$min \sum_{n,s} [c_{n,s}\bar{e}_{n,s} + c_{n,s}\bar{g}_{n,s}] + \sum_{l} c_l F_l + \sum_{t} \sum_{n,s} [o_{n,s,t} g_{n,s,t} + o_{n,s,t} h_{n,s,t}] \quad (1)$$

To express capital costs in annual costs, the annuity factor $\frac{1-(1+dr)^{-lf}}{dr}$ was used, where dr is the discount rate and lf the lifetime of the technology [31].

The satisfaction of the demand, with the power flow $f_{l,t}$ in MW and K_{nl} the incidence matrix of line l at substation n is defined by Eq. (2):

$$\sum_s g_{n,s,t} + \sum_s h_{n,s,t} - \sum_l K_{nl} f_{l,t} = d_{n,t} \tag{2}$$

For the optimisation of the size of the installed generation power capacities, Eq. (3) is implemented:

$$\bar{g}_{n,s} \leq \underline{g}_{n,s} \tag{3}$$

The operation of the batteries is defined in Eq. (4), with $\eta_{n,s}$ the standing losses, considered zero in the modeling of this study. No efficiency losses for power going into and out of the storage are considered.

$$e_{n,s,t} = \eta_{n,s} e_{n,s,t-1} - h_{n,s,t} \tag{4}$$

A constraint for limiting the annual production of a sector has been introduced in Eq. (5)

$$\sum_t g_{n,s,t} \leq \text{MaxProd} \tag{5}$$

Indeed, some electrical productions are limited, like hydropower or biomass, according to available local resources. These limits ($MaxProd$ in MWh) have been set according to data from the literature.

The necessary reinforcement of high voltage lines are defined by Eq. (6). The current limit of apparent power of the lines was defined with data from [21].

$$|f_{l,t}| \leq F_l \tag{6}$$

To implement the model, the Python for Power System Analysis (PyPSA) framework [32] is used. The optimisation problem is solved with Gurobi [33].

4. Results

4.1. Technical comparison

Different results were obtained from the optimisation of the simulated system. The sizing of power generation facilities when optimised, the electricity produced per sector and per substation, the required size of the batteries and their operation, and the required reinforcement of the high voltage lines

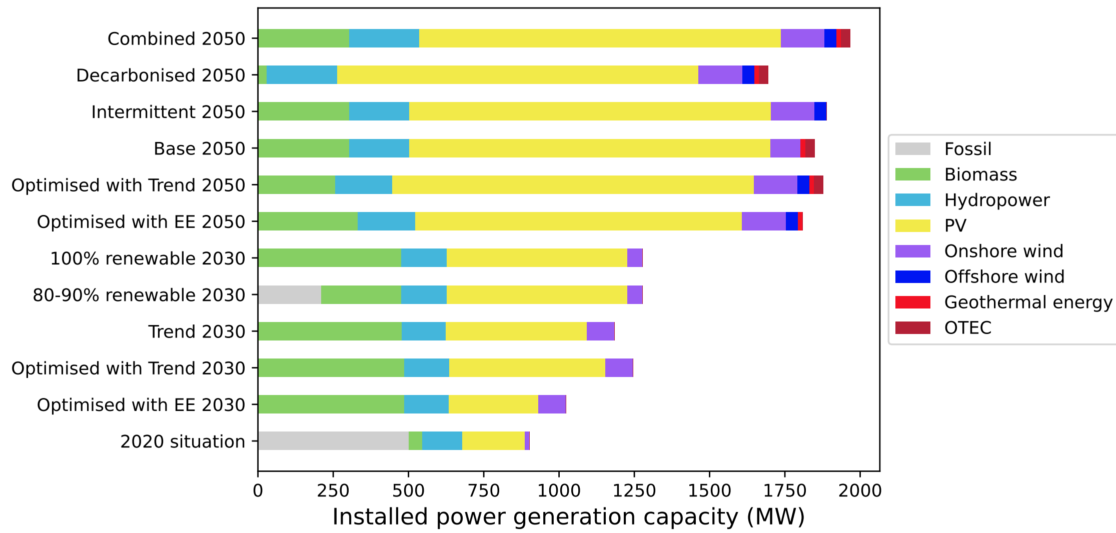


Figure 7: Installed capacities (MW) for the 2030 and 2050 scenarios.

were displayed. The sizing of the electricity generation scenarios was made for 2030 and 2050, in order to satisfy the two consumption scenarios chosen. The results of this sizing are shown in Figure 7. The other results for the simulation of the power system over the year are shown in Table 1, together with the simulation results of the pre-designed scenarios.

For the sizing of installations for 2030, in both consumption cases, wind installations are prioritised over PV installations, although the prices of the latter are higher. This is justified by the minimisation of storage needs in order to smooth out PV production. No reinforcement of the grid power lines will be necessary in the medium term.

For all three pre-designed scenarios, larger amounts of batteries are required with the EE power consumption scenario. With a higher share of intermittent energy in the electricity mix and lower electricity demand, energy can be stored when it is not consumed. Conversely, the Trend consumption scenario consumes more intermittent energy, leaving the missing demand filled by controllable generation. However, batteries are not used in the same way depending on the demand; while relatively small batteries (2 - 5 MWh) are installed at all substations with the Trend scenario, larger batteries (up to 70 MWh) are installed at less than half of the substations in the other scenario. These are shown in Figure 8a. These include the substations

Scenario	Battery need, EE (MWh)	Line reinforcement, EE (MVA)	Battery need, Trend (MWh)	Line reinforcement, Trend (MVA)
Optimised 2030	0	0	168.5	0
Trend 2030	21.856	0	0	0
80-90% ren. 2030	184.51	0	88.15	0
100% ren. 2030	184.51	0	88.15	0
Optimised 2050	1746	11	1924	13
Base 2050	1747	4	**x**	**x**
Intermittent 2050	2342	0	**x**	**x**
Decarbonised 2050	**x**	**x**	**x**	**x**
Combined 2050	2342	0	2041	5.2

Table 1: Results of the simulations of every production scenario with every consumption scenario. Crosses mean that the system is not technically feasible.

where the five largest photovoltaic capacities have been added. The other substations concerned have either PV power additions or low installed power (around 10 MW). For the latter, the battery allows the electricity produced at another station to be stored to meet local demand. This shows the advantage of the sizing of the electricity production facilities: the storage requirements are optimised with the two consumption scenarios proposed. In the case of the Trend consumption scenario, storage requirements are greater with the sizing of the facilities because of the lower installed capacity of hydroelectric power.

Looking at the 2050 horizon, the Trend and EE consumption scenarios are different than for 2030, as the additional demand for electric vehicles is taken into account here. Once again, installations are sized to minimise the need for electrical storage. It should also be noted that the geothermal potential is required in both electricity consumption scenarios. In the case of the Trend consumption scenario, the OTEC installation is essential to meet demand. Thus, with regard to the pre-designed scenarios, the Base and Intermittent scenarios are not feasible in combination with the Trend consumption scenario. Moreover, the Decarbonised scenario is not feasible with both consumption scenarios. In both case, demand is too high to be met by the installed capacities defined in the scenarios. While storage is needed in all feasible simulations, less is required for pre-designed scenarios where reinforcement is needed on the electricity transmission network. This

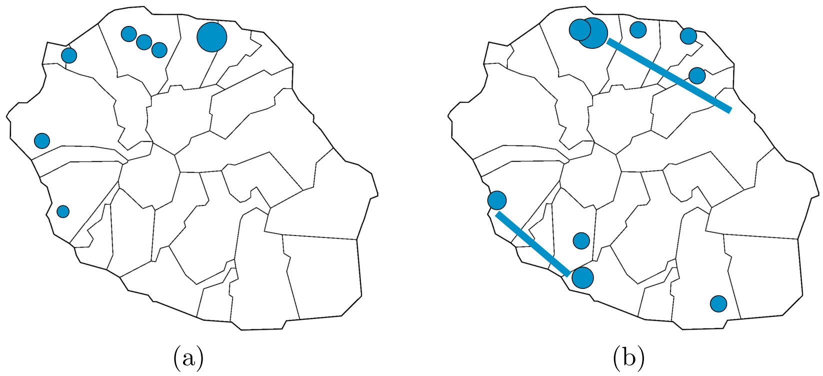


Figure 8: Comparison of requirements for battery and line reinforcement; (a) 2030 scenarios.; (b) 2050 scenarios.

concerns the Base scenario with EE consumption, and the Combined scenario with Trend consumption. The same line requires an increase of 4 MVA for the first simulation and 3 MVA for the second. The second simulation requires a second increase of 2.2 MVA for another line. These same two lines need to be reinforced when sizing installations. They connect substations where large storage is required, due to a high PV potential or a large number of connected power generation facilities. These are shown in Figure 8b. The other substations concerned by large storage (+ 100 MWh) are connected to high electricity consumption (commune of Saint Denis), high PV potential, or high or low installed power, all energies combined. The substations requiring the least additional storage are mainly the substations connected to large hydraulic installations and having no connected electricity consumption.

The impacts of a 100 % electrified fleet of which only 40 % are controllable can be noticed in the storage requirements. Indeed, with an EE scenario, a need of + 7 % in storage is noticed, and for a Trend scenario a need of + 8 %. The results on the lines or on the electrical generation are globally not impacted.

4.2. Investment costs comparison

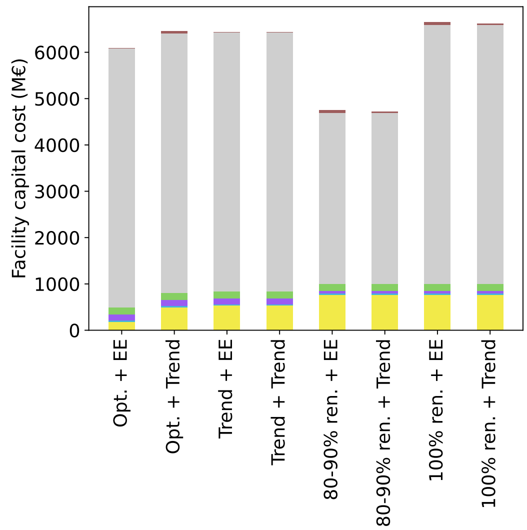
The scenarios introduced can first be economically compared. Facility capital costs allow a comparison of the economic investments required in order to reach the targeted horizon. The data used for the calculations can be found in Table C.4. Data for line reinforcement were taken from [21]. Regarding the 2030 scenarios, only facility capital costs for new electricity generation capacity compared to the current situation are considered. Investments are almost similar for the sizing scenarios and the Trend and 100 % renewable pre-designed scenarios, as can be seen on Figure 9a, as the installed capacity data are close. The main difference with the 80 - 90 % renewable scenario is in the investment for the conversion of diesel engines to liquid biomass [34]. Comparing the 2050 scenarios, the four scenarios have fairly similar investment costs in facilities (see Figure 9b). The costs of reinforcing the network are not shown in the diagrams, being in the region of a hundred thousand euros for the lines concerned.

4.3. Environmental comparison

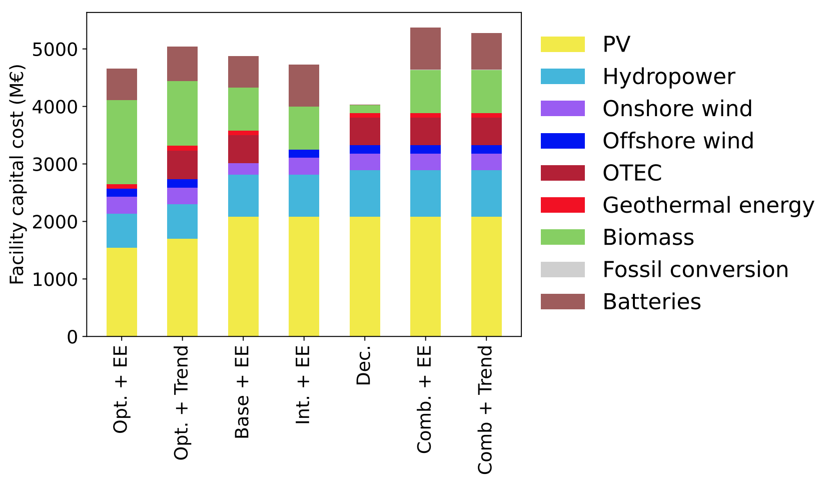
The scenarios presented can also be compared from an environmental perspective. The data used for the calculations can be found in Table C.5.

Land requirement is first observed, because of the limited availability of this resource on the island. Comparing the 2030 scenarios, both the 80 - 90 % renewable and 100 % renewable pre-designed scenarios require almost six square kilometers, one more than for the remaining scenarios. Indeed, the footprints of hydroelectric and photovoltaic systems are larger than those of wind power plants for an equivalent capacity, which explains the difference. Looking at the 2050 scenarios, the Combined scenario would require 84 km^2 of land, namely 3 % of the island's surface. In comparison, the Decarbonised scenario would require only 50 km^2. As this horizon is considered from scratch, the current installations on the island would be included in this total, unlike the scenarios for 2030.

Considering a second resource with limited availability on the island, the use of water is studied. This criteria is about the water taken from the environment by the electrical installation during its construction and its operation, and not returned to its original source [35]. PV is the only technology where the water requirement during operation is zero. Moreover, the water consumed during the manufacturing of the panels could be neglected at the local level, as the panels have to be imported. For the 2030 horizon, the results are similar between the scenarios. Between a Trend consumption scenario and an EE one, 100 additional cubic decameters of water are required, regardless of the installed power pre-designed scenario, as shown in Figure 10a. Looking at the other horizon, the optimised scenario with the Trend consumption scenario comes out on top, due to a higher use of local biomass resources than the other scenarios, as can be seen in Figure 10b.



(a)



(b)

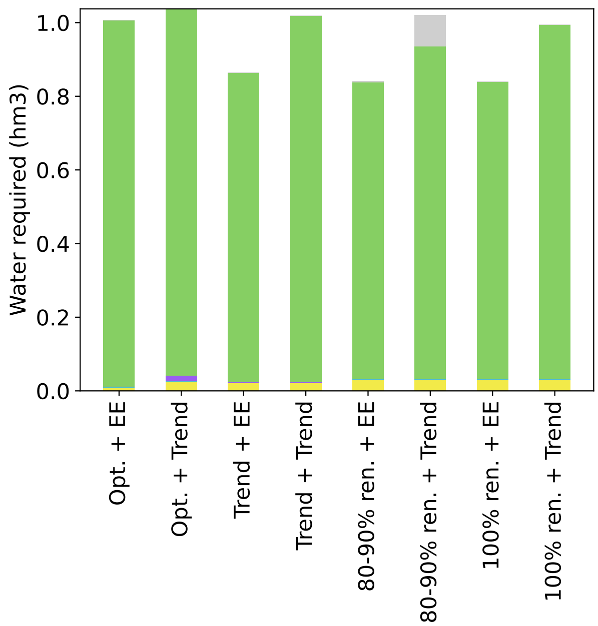
Figure 9: Comparison of facility capital costs of the different scenarios; (a) 2030 scenarios; (b) 2050 scenarios.

In both figures, the impact of biomass is predominant, requiring more water during its operation. Moreover, over both horizons, the optimised sizing scenarios consume more water than the pre-designed scenarios. Thus, if the former had been optimised according to this water consumption criterion, different results would have been obtained.

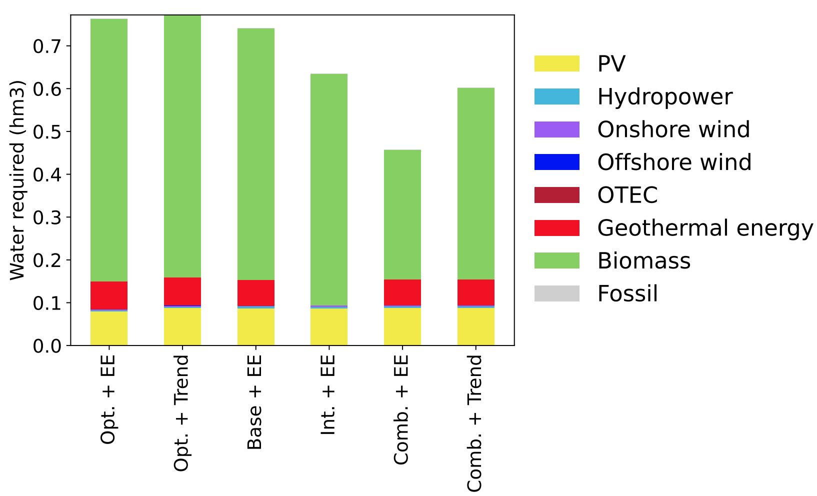
Lastly, life cycle greenhouse gas (GHG) emissions are depicted to assess the environmental impact of the scenarios. Among them, CO_2, CH_4 and NO_2 emissions, all measured in CO_2 equivalence. For the study, emissions from electrical installations were assessed, as well as electricity generation emissions over the simulated year. As expected, for 2030 the 80 - 90 % renewable energy scenario with the Trend consumption scenario is the one emitting the most GHG emissions over the life cycle of the new facilities, as shown in Figure 11a. These emissions amount to 124 kilotonnes of CO_2eq, while the only direct CO_2 emissions for electricity production were 1 922 kilotonnes in 2019 [27]. Moreover, with this same installed capacity scenario, switching from the Trend electricity consumption scenario to the EE one leads to a decrease of 71 kilotonnes of CO_2eq. Indeed, during the optimization, only the production costs of the power generation facilities were considered. Thus, the use of the diesel power plant in this scenario is in the minority, as the import costs are high compared to the maintenance costs of the facilities using local resources. The impacts of future biomass imports could not be assessed, since their introduction is scheduled for 2024.

As for water requirements, in the long term the optimised sizing scenarios have highest life-cycle GHG emissions, with almost 39 kilotonnes of CO_2 emitted. Once again, if they had been optimised according to this criterion, different results would have been obtained. The pre-designed scenario Combined with an EE consumption would be the one with the lowest CO_2 emissions, with 19 kilotonnes, as shown in Figure 11b. Once again, the impact of the biomass industry is predominant in both figures, emitting the most during its operation.

The comparison of the different criteria can be seen in Figure 12. Each criterion is standardized according to the minimum and maximum results of each scenario. The more outwardly oriented the simulation, the greater the impacts are.

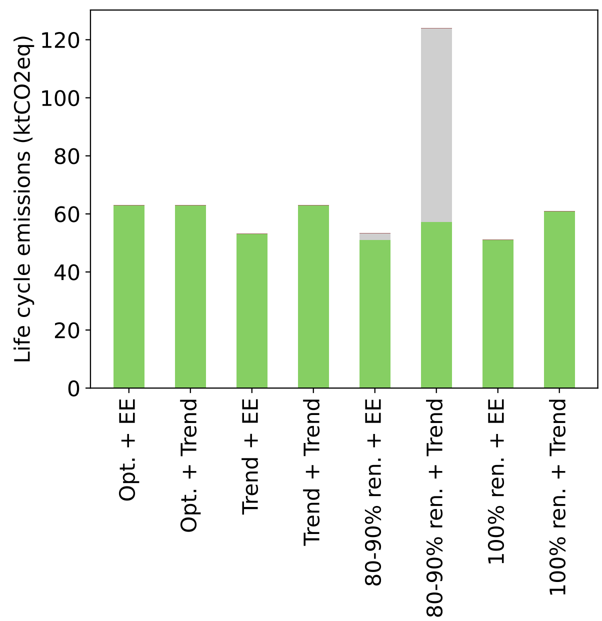


(a)

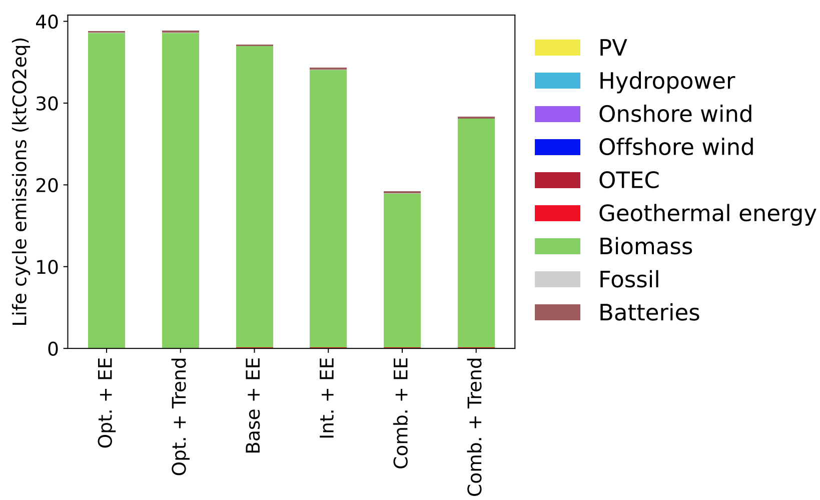


(b)

Figure 10: Comparison of the water volume needed in the different scenarios.; (a) 2030 scenarios.; (b) 2050 scenarios.

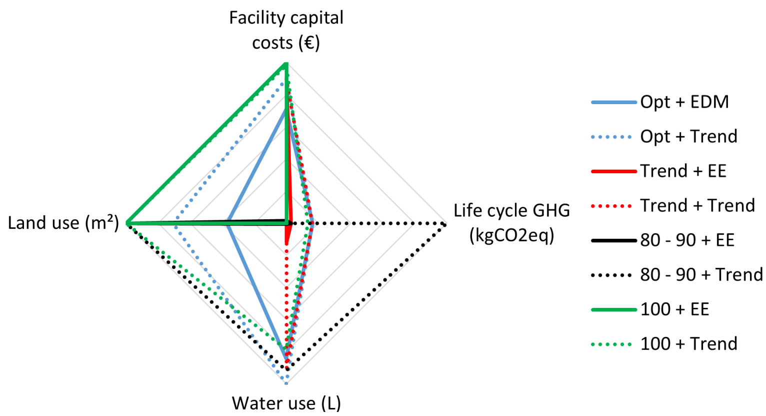


(a)

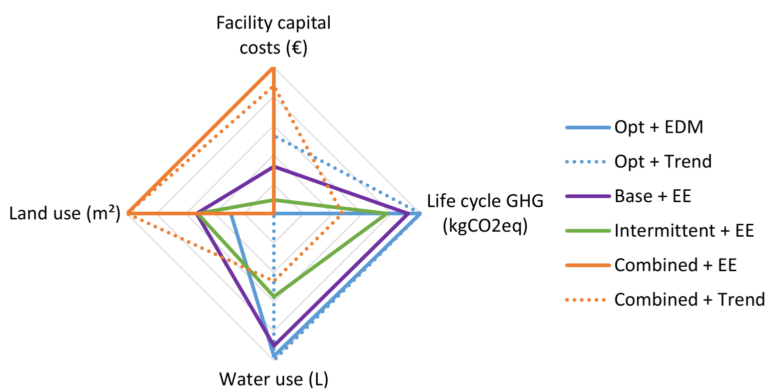


(b)

Figure 11: Comparison of life cycle emissions of the different scenarios.; (a) 2030 scenarios.; (b) 2050 scenarios.



(a)



(b)

Figure 12: Representation of the different simulations on the selected criteria. Results are normalised on each criterion for each horizon; (a) 2030 simulations; (b) 2050 simulations.

5. Discussion

The scenarios introduced for 2030 and 2050 have been simulated, and results were obtained and detailed. It has been demonstrated that, in order to satisfy a steady long-term electricity demand with a fully electrified vehicle fleet in Reunion Island, it is necessary to mobilise all possible electricity production technologies. If this is not possible, electricity consumption will have to be at least below the level of the EE scenario introduced in the present study. Then,between one scenario or another, the impacts are close, with the capital cost of the facilities being globally related to land use and life-cycle GHG emissions related to water use (for 2050). If the biomass sector was no longer used for electricity generation, electricity consumption would have to decrease even more, below 4 GWh annually, including the consumption of electric vehicles. To achieve this long-term horizon, decisions will have to be made in the medium term. If the total cessation of fossil power from 2030 implies a significant decrease in life cycle GHG emissions, it has a consequential cost. One of the best path to follow would be to maintain one of the thermal power plants with a decrease in consumption. All indicators would be at their minimum, except the use of land, which could be considered negligible in relation to the needs in 2050.

In the simulation of the 2030 scenarios, the new capacities to be installed per substation have not been uniformly distributed: the substations capacities were considered. As a result, some substations have not been allocated any additional power by 2030, although in some cases there is potential. This may justify the need for batteries in some places. In addition, some of these batteries may be large (290 MWh). In the medium and long term, hydrogen storage could be introduced, in order to evaluate the economic and environmental use of this type of storage in such a system.

In the work presented, only a few comparison criteria were considered; others could have been considered as well, which would have led to different conclusions [36]. For example, the use of specific metals and materials could have been observed. This criterion is important when considering the environmental and social impact of extracting certain metals or manufacturing certain materials. The results could have also been different if the impact of climate change was included in the modeling. For the simulation of the photovoltaic and wind models, weather data from 2019 were used. The production of these energies could vary greatly in the future, and may well increase or decrease. Similarly, the production limitations of the hydro and biomass sectors were determined using the literature. Here again, the production is uncertain in the future due to climate change. Other uncertainties exist and can hardly be evaluated in such a model, such as new energy laws or new conflicts. The latter can jeopardize the current fossil imports, but also the future imports of pellets or oil. Energy reliability was also not studied in the paper.

A similar work could be done in other territories. Even if each island has its own conditions and data [14, 37], the methodology set up in this article is replicable and the developed optimisation model can be used for any non-interconnected area by changing the input data. Some modifications would be necessary to model islands connected to the mainland, as is the case of Corsica for example, in order to consider an import and export of electricity to an external market. Each study on a different territory would lead to different results, and it would thus be interesting to compare the costs and environmental impacts involved in the transition required by the law on Energy Transition for Green Growth to the French islands to achieve energy autonomy.

6. Conclusion

In the present study, different scenarios have been investigated for the evolution of Reunion Island's power system for 2030 and 2050, with a view to achieving electrical autonomy in the latter period. Simulations have shown that, from a GHG emissions point of view, the conversion of the current fossil power plants is impacting. However, it has not been possible to assess the impact of the imports planned as offsets, since their introduction is scheduled for 2024. Incidentally, following an EE plan for electricity consumption could reduce costs and environmental impacts, although further studies would be required to evaluate the wider economic and societal impacts.

To achieve energy autonomy, new sources of electricity production will have to be developed. The development of geothermal energy, ocean thermal energy conversion and offshore wind turbines has been studied in the work presented. The reduction of the biomass sector could be considered in the future, but it must be accompanied by a strong decrease in electricity consumption. The future of these sectors and their long-term role in Reunion's energy context is a major source of uncertainty, which should be resolved in the decisions taken in the short or medium term.

The present study has shown that energy transition must be supported by significant storage facilities. Although only batteries have been considered in the present work, the use of hydrogen storage will be employed in a future work, to consider longer-term storage to complement short-term battery storage. Moreover, a modeling of the storage in the form of energy was carried out in the study. As these are very solicited, a power modeling will be carried out later in order to compare the two systems.
Hydrogen will also be introduced to decarbonise the rest of the road transport sector; in the present study, heavy transport vehicles, such as buses or trucks, have not been taken into account to achieve energy autonomy in 2050. The decarbonisation of the aviation and maritime sectors will be also be studied in future work.
Lastly, social impact of electric autonomy was not measured in the presented paper. It is necessary to assess the acceptance and local impacts of some new electricity production methods or storage facilities. This will be the subject of further work in the continuation of the study, as well as the social impact of energy autonomy as a whole.

CRediT authorship contribution statement

Agnès François: Conceptualization, Methodology, Software, Formal analysis, Writing - Original Draft. **Robin Roche:** Conceptualization, Writing - Review and Editing, Supervision, Project administration. **Dominique Grondin:** Conceptualization, Writing - Review and Editing, Supervision. **Michel Benne:** Conceptualization, Writing - Review and Editing, Supervision.

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Appendix A. Characteristics of the territory

See Table A.2.

Table A.2: SWOT analysis of the territory.

Strengths	**Weaknesses**
- Dense hydrographic network (400GWh every year for two decades) - Good photovoltaic potential (200GWh every year since 2013) - Geothermal potential - Marine energy potential (ocean thermal energy conversion, wave energy, offshore wind turbines) - Tropical climate (negligible heat demand)	- Cyclonic episodes - Dependence on imports - Isolation of the island - Waste exportation - Limited land

Opportunities	**Threats**
- National energy policy - Train or tramway potential (cite, cite)	- Energy dependency

Table B.3: List of the scenarios of installed power generation capacity.

Source	Publication year	Original scenario name	New scenario name	Specificity
[18]	2009	-	PETREL.Trend	Business-as-usual
		STARTER	PETREL.Autonomy	Achieving energy autonomy by 2030
[19]	2013	-	SRCAE.Trend	Business-as-usual
[26]	2015	BASE	Drouineau.Base	Business-as-usual
		RENEW	Drouineau.Renew	100 % renewable electricity generation in 2030
		RENEW-HighInt	Drouineau.RenewHighInt	100 % renewable electricity generation in 2030 with greater increase in photovoltaic and marine energy
		RENEW-Cane	Drouineau.RenewCane	100 % renewable electricity generation in 2030 with decline of the sugar industry
[21]	2018	Trend	ADEME.Trend	Business-as-usual
		Thermal advantage	ADEME.Thermal	Economic context favourable to conventional energy
		Technological advantage	ADEME.Technological	Access to new renewable energy production technologies
		All green lights	ADEME.Green	100 % renewable electricity generation in 2030
		Towards energy autonomy	ADEME.Autonomy	Achieving energy autonomy by 2030
[22]	2019	Azur	EDF.Azur	Soft energy transition
		Emerald	EDF.Emerald	Strong energy transition
[20]	2020	-	PPE.Autonomy	Almost 100 % renewable electricity generation in 2030

Appendix B. Scenarios of installed power generation capacity

See Table B.3.

Appendix C. Data used for the modelling

See Tables C.4 and C.5.

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Generation technology	Investment (€/kW)
PV Residential	1900
PV Tertiary	1550
PV Ground	1000
PV Canopy	1230
Hydropower Pumped storage, dam	3800
Hydropower Run-of-the-river, irrigation and sewage networks	2000
Hydropower Drinking water network	5200
Onshore wind	2000
Offshore wind	3500
OTEC	16200
Geothermal energy	5350
Biomass Biogas plant	5400
Biomass Bagasse thermal power plant	2200
Biomass Small thermal power plant	2200
Biomass Waste-to-energy plant	7850
Batteries	310 €/kWh

Table C.4: Investment data used [21, 28, 38].

Table C.5: Sustainability criteria data used [35, 39, 40, 41].

Generation technology	Life cycle GHG ($kgCO_2eq$ /MW)	Life cycle GHG ($kgCO_2eq$ /GWh)	Water use (L/MW)	Water use (L/GWh)	Land use (m^2/MW)
PV Residential, tertiary	92	0	72952	0	1561
PV Ground, canopy	92	0	72952	0	1561
Hydropower Pumped storage, run-of-the-river	53	0	16587	208	190606
Hydropower Dam	53	0	16587	208	190606
Hydropower Water systems	53	0	16587	208	190606
Onshore wind	39	0	11048	2020	3950
Offshore wind	41	0	3660	130	31
OTEC	0	0	16587	208	31
Geothermal energy	49.9	0	18000	500000	18391
Biomass	0	35000	16587	553000	120236

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