Assessing a Transition to 100% Renewable Power Generation in a Non-interconnected Area: A Case Study for *La Réunion* Island

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Abstract

In this paper, we present a comprehensive, multi-timescale approach to evaluate energy transition policies aiming at fully renewable generation in power systems of non-interconnected areas, typically islands or remote regions. The approach links three dynamic models: (i) a capacity expansion model, ETEM-SG, proposes an investment and generation plan for typical days, up to 2030; (ii) a simplified dispatch model is used to validate the generation plan for a full year of weather data and demand variations; and (iii) a static and dynamic analysis of the power system is used to assess the stability of the new power system for rapid events such as a sudden reduction of renewable generation. The proposed three-step approach generates a cost-effective long-term investment planning that ensures the balance between supply and demand at an hourly time step and the stability of the power system at a timescale of milliseconds. The presentation is based on a case study fully described in a report [1] made with ADEME, the French Agency for Ecological Transition, for the French island of *La Réunion*. It shows how a reliable 100% renewable power supply is achievable by 2030, in this area.

Keywords Long-term energy planning · Dispatch model · Network stability · Variable renewable energy · Reserve requirements.

1 Introduction

The sustainable transition generally calls for the design of an energy policy that aims for an electricity supply system-based mainly, if not exclusively, on renewable energies (RE) by 2030 or 2050. In France, for example, ADEME, the French Agency for the Environment and Energy Management[1], carried out an energy forecasting exercise for its urban area in 2012, called *Visions* 2030-2050. In this study [2], significant renewable energy production potentials were

identified and judged sufficient to cover the total energy demand in 2050.

However, although solar and wind energy sources are weather dependent, resulting in intermittent production, these results were mainly based on annual energy volume considerations. The question then arose as to whether an electricity system based mainly on these renewable energy sources could guarantee a quasi-permanent supply–demand balance and the necessary stability of the networks. Another concern, particularly important for non-interconnected areas, usually islands or remote regions, was to identify the need for reinforcement and extension of the electricity transmission network due to the new geographical distribution of production units (e.g. wind or solar farms). It was then necessary to assess the stability of the new electricity system with an adapted transmission network. ADEME therefore wished to adapt its approach to this reality, by addressing the transition to sustainable electricity systems in the non-interconnected regions of France[2].

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1 Agence de l'Environnement et de la Maîtrise de l'Énergie - *Agence pour la transition écologique*.

2 This comprised islands of *La Réunion*, Mayotte, Corse, Guadeloupe, Martinique, and French Guyana.

Fig. 1 A global approach for designing transition to 100% renewable electricity generation
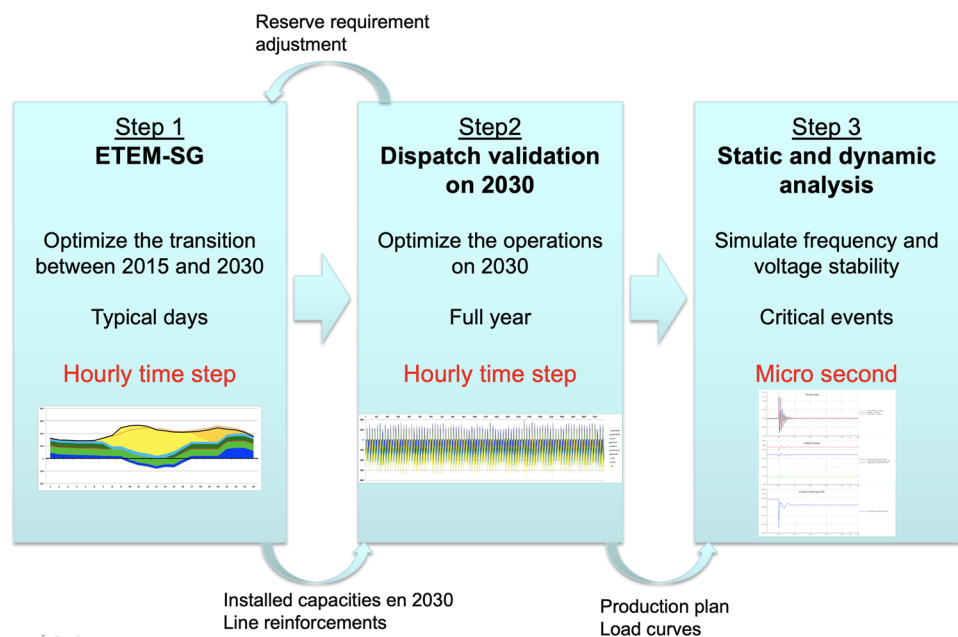
There are many modelling approaches for planning a transition to a low-carbon electricity system with massive integration of renewable sources; see, for example, [3] for a recent application of robust optimization to provide decision support in energy planning, or the "open energy modelling framework" proposed in [4]. The open energy model PyPSA [5], a TIME model, is also applied to assess the impact of renewable energy on the energy sector of the island of *La Réunion* [6], and in [7], an application of MARKAL is performed to assess the factors influencing low-carbon electricity generation.

In general, these approaches do not take into account power system reliability constraints in the energy model. This was done in [8], where the authors, using thermodynamic considerations, introduce two reliability indicators into their TIMES model, as a way to deal with the very different timescales involved. They argue that these two indicators, which measure magnetic and kinetic reserve, allow the reliability of a given generation mix to be quantified. This would permit a first assessment of a trade-off between increasing the share of intermittent generation units and maintaining an expected level of reliability. In a different approach [9], energy distribution constraints are introduced in the ETEM-SG model; they are associated with intermittent and volatile renewable energy sources connected to the transmission or distribution network. The model thus takes into account the ability of distributed energy resources (DER) to provide reserves, reactive power compensation and time shifting of their operation in order to reduce losses, congestion and wholesale energy costs. Thus, ADEME adopted an approach of using ETEM-SG, complemented by

an hourly dispatching study for a full year of weather events and a network stability analysis for fast timescale events.

Remark 1 *La Réunion* Island is a tropical island prone to extreme events, such as typhoons. These extreme events are not taken into account in the analysis of the supply–demand balance. However, the choice of technologies, such as folding wind turbines, is adapted to these conditions.

The rest of the paper is organized as follows: In Section 2, we describe a comprehensive approach that uses three complementary tools to design and validate reliable long-term energy policies with a 100% renewable energy target. In Section 3, we present the case study of *La Réunion*, a French island in the Indian Ocean used to validate our approach. In Section 4, we detail the in-depth techno-economic analysis. Finally, in Section 5, we conclude and consider future developments.

2 A Global Multi-level Approach

A three-tiered approach, illustrated in Fig. 1, is used to design a least-cost, robust and reliable transition to a 100% renewable energy target for non-interconnected areas.[3]

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[3] Robustness and reliability refer to (i) the ability to achieve balance between supply and demand for typical annual weather sequences and (ii) the design of a power system that remains stable in the event of unforeseen disturbances.

In the first level, the ETEM-SG techno-economic model proposes a cost-efficient transition to 100% renewables by 2030 for the electricity sector of the region under consideration; in this power system design, specific constraints ensure that hourly supply–demand balance and secondary reserve requirements are met on a set of typical days for different seasons. The second level validates the proposed power system by simulating a full hourly power dispatch for a target year, with a full history of hourly weather and demand variations. Adjustments to the reserve requirement are then introduced into ETEM-SG when dispatch is not feasible. Finally, at the third level, a static and dynamic analysis of the power system is carried out to ensure frequency and voltage stability in case of critical events. It is here that a decision can be taken, if necessary, to reinforce the network and to invest in technologies that provide fast reserves. These three modules are now described in more detail.

2.1 Tier-1: Long-term Capacity Expansion and Dispatch Models

ETEM-SG is a multi-sector, multi-energy and technology-rich model (see Fig. 2) specifically designed to analyse the energy transition at the regional level with a focus on the development of a smart electricity system. A full description of the ETEM-SG model is provided in [9]. A presentation of the possibility to represent demand response and distribution constraints and options in ETEM-SG is given in [10]. The representation in ETEM-SG of power flow constraints and nodal marginal prices is described in [11]. ETEM-SG is a linear programming model, related to the TIMES family of models [12–14].

In its standard version, the model is driven by exogenously defined useful energy demands (i.e. demand for energy services) and imported energy prices. All technologies are defined as resource transformers and are characterized by technical coefficients describing inputs and outputs,

efficiency, capacity limits, date of availability (for new technologies), lifetime, etc. The economic parameters define the costs of energy use and the costs of energy supply. The economic parameters define the investment, operation and maintenance costs for each technology. The planning horizon is usually long enough to allow the energy system to have a complete technology mix turnover.

Typically, ETEM-SG proposes an optimal development path for an efficient regional energy system with a planning horizon of 20 to 50 years generally divided into periods $t \in T$ of 1 to 5 years (5 years in the simulations presented in this paper). In each period, a few typical days are considered (e.g. 6 days corresponding to the three seasons—winter, summer, spring–autumn—and two types of weekdays—workday, weekend–holiday). Each of these days is subdivided into hours or groups of hours to finally obtain a set of time slices $s \in S$ that will be used to represent load curves, demand distribution and resource availability in different seasons and at different times of the day. This temporal structure is particularly important to correctly represent the dynamics of demand and how its flexibility can be exploited (e.g. through demand response mechanisms).

ETEM-SG calculates an investment plan and a supply–demand balance at each time slice for a set of typical days. In order to adapt to possible variations in demand (in particular, peak demand) and to compensate for the intermittency of variable renewables (e.g. wind and solar), reserve requirements are then modelled in ETEM-SG as follows:

2.1.1 Reserve for peak demand

At each time slice, the ETEM-SG is informed of the average demand to be met and the range of maximum variations observed in the past on that time slice. The ETEM-SG then guarantees the additional generation and/or storage capacities that can be mobilized to overcome these maximum variations in demand.

Fig. 2 Reference Energy System
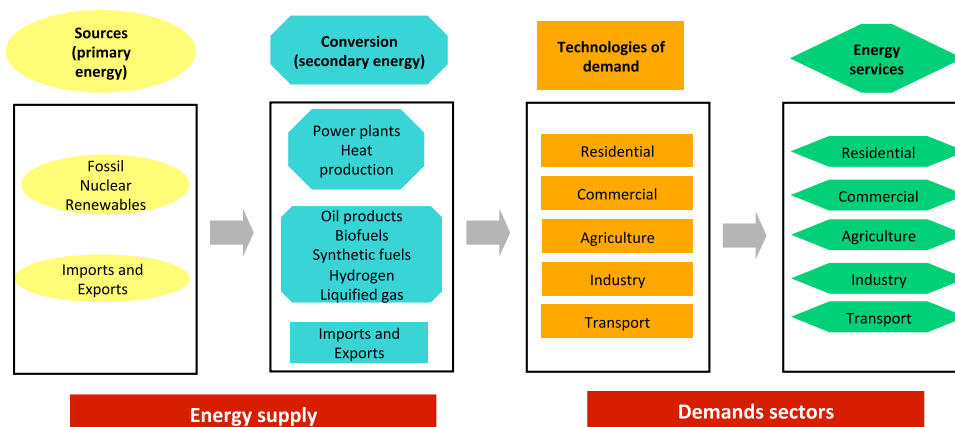
2.1.2 Reserve for intermittency

At each time step, the ETEM-SG determines the proportion of variable renewable generation in the mix. Part of this variable generation is then covered by an additional reserve that can be mobilized quickly in case of a sudden loss of generation. ETEM-SG requires this reserve to be higher than a given ratio of variable renewable generation at each time slice. In practice, a ratio between 50 and 100% is chosen. In Level 2, a full-year dispatch at an hourly timescale validates this reserve requirement, if it is feasible. If it is not feasible, the ratio must be increased. In our case study, we use a ratio of 70%.

The fast reserve needed for the stability of the network, such as the kinetic energy related to the inertia of the rotating masses, is evaluated in the dynamic study of the network, described in Section 2.3.

2.2 Tier-2: Dispatch Validation and Reserve Adjustment

To validate and adjust the reserve requirements used to cope with the intermittency of Variable Renewable Energy (VRE) in the generation plan proposed by ETEM-SG for a given year, a full-year dispatch is solved, with an hourly time step (8760 hours), assuming representative annual demand and weather time series. These time series are constructed using the Typical Meteorological Year (TMY) methodology which generates an annual profile representative of a most plausible/typical/normal year. It consists of selecting, for a given whole month, the measured hourly values of the month closest to the average month calculated over the period for which historical data were

available (generally 10 years). These are not average values on a historical basis, but series of actual values measured for a given month, the month closest to the average month over the period.

Starting from a low value around 50%, the reserve ratio for intermittency used in ETEM-SG is gradually increased when the infeasibility of the dispatching problem is observed.

Remark 2 Note that a perfect forecast optimization is performed in this simplified power dispatch model. If possible, the resulting dispatch schedule proves that there is a possible balance between supply and demand on an hourly basis for a typical sequence of weather conditions over a full year. A full-fledged power dispatch model would have required a stochastic programming/control modelling approach, which was beyond the scope of this study.

2.3 Tier-3: Static and Dynamic Analysis

The static and dynamic analysis aims to validate the optimized electrical system by considering the physical constraints related to the operation of electrical systems. This analysis is carried out on certain critical operating situations selected from the dispatching results which correspond to situations that are particularly constraining for the stability and the static operating limits of the power system. The power system analysis is performed with PowerFactory [15], a reference tool for power system simulation, analysis and modelling. It provides a library of typical models for different types of equipment and control systems (IEEE).

In the static analysis, the state of the power system at a given moment is observed in order to verify that the energy

Fig. 3 Transmission grid of *La Réunion*

Electric grid of the La Réunion island
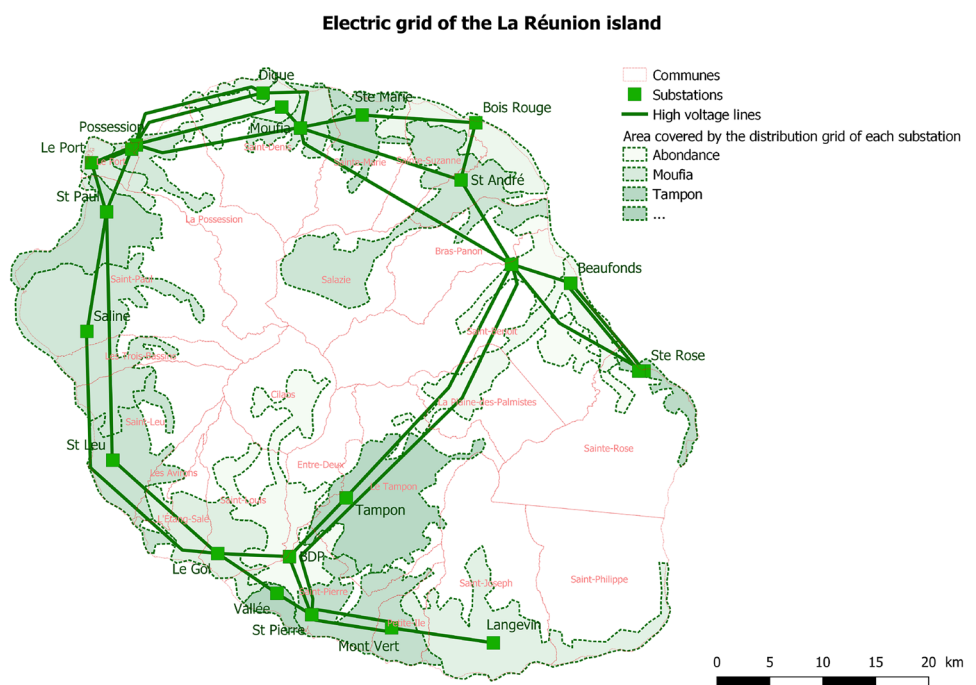
Fig. 4 Sectorial demand for the MDE+ scenario
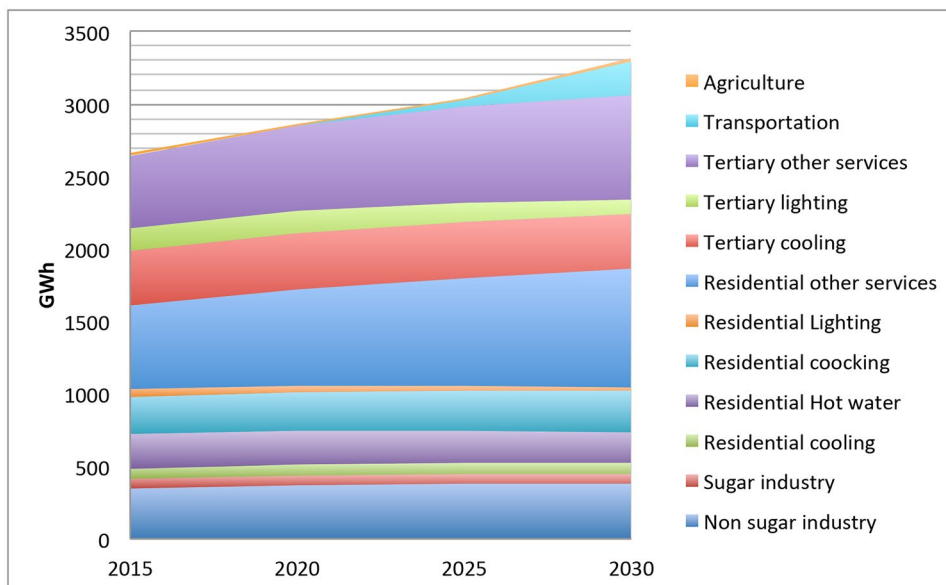
mix complies with standard network rules. The tool calculates the power flows (or load flows) and makes it possible to determine how the generated power is distributed on the network and what the consequences of this distribution are on the electrical quantities of the network. In particular, the following points can be observed:

- Overloaded lines with respect to the maximum allowable current under steady-state conditions (Imap).
- Voltage plan induced by the power flows and possible problems of network over- or under-voltage.

Based on these observations, reinforcement recommendations are proposed (e.g. reinforcement of transmission lines, additional reactive compensation equipments, dynamic operating rules of the generators, etc.). This static analysis is performed on three of the most demanding critical hours observed in the dispatch simulation.

The dynamic analysis concerns transient stability. It consists in checking the stability of the electrical system following an extreme situation, e.g. a short-circuit default or the loss of a production group. The objective is to verify the stability of the electromechanical variables of the system, in the sense of asymptotic stability. Stability is observed with regard to voltage, frequency and alternators (angular stability). In order to guarantee the stability of the system, all these variables must remain in the admissible value ranges imposed by the operator.

3 The Case Study of *La Réunion*

In this section, the model used in the case study of the French island *La Réunion* is described. It has been used by ADEME to discuss with local authorities a possible transition of the power sector to 100% renewable production in 2030.

3.1 Time Set

The transition is represented on three 5-year periods from 2015 to 2030. To capture the different patterns of demands and of VRE production, we consider 8 typical days: a week day and weekend day for each of the four seasons. Each typical day is then decomposed in 24 hours. Each period thus contains 192 time slices.

3.2 Transmission Network

The model includes a description of the transmission network shown in Fig. 3. The costs associated with reinforcing the transmission network are taken into account.

Remark 3 The scope of this study did not require the modelling of distribution lines, which would have generated a much larger model without obtaining a more relevant overview.

Table 1 Technologies with costs and potentials in 2030

Technology	Investment cost k €/ MW	Fixed O&M Cost k €/ MW	Variables O&M k €/ MW/h	Potential MW
Solar				
Residential roof (N/S)	1540	16.8	-	610.5
Residential roof (E/W)	1540	16.8	-	154.6
Tertiary roof < 2000m^2 (N/S)	1240	16.8	-	126.5
Tertiary roof < 2000m^2 (E/W)	1240	16.8	-	43.5
Industrial roof > 2000m^2 (N/S)	1240	16.8	-	105.6
Industrial roof > 2000m^2 (E/W)	1240	16.8	-	17.0
Ground	800	12.6	-	94.2
Parking roof	990	16.8	-	29.2
Hydroelectricity				
Drinkable water adduction	5150	206	-	1.2
Irrigation network	1980	79	-	5.3
Sanitation network	1980	79	-	0.1
Dam	3720	112	-	128.2
Run-of-river dam	2380	56.7	-	57.6
Marine pumped storage	6420	192	-	50
Ocean Thermal Energy	16200	-	0.25	7
Wind				
Onshore	2380	60	-	142.5
Offshore	5060	-	0.15	50
Biomass				
Thermal power plant (bagasse/coal/biomass)	4500	163	0.07	381.9
Thermal power plant (sugar cane)	2160	93	0.13	14.5
Thermal power plant (green waste)	2160	93	0.13	4.3
Thermal power plant (biowaste)	2160	93	0.13	1.3
Incineration plant	7700	290	-	53.7
Small biomass plant	2160	93	0.35	5.1
Bioethanol	1470	87	0.071	41.0
Biogas	5240	90.6	0.17	29.9
Geothermy				
Deep	5350	123	0.012	15
Battery				
Lithium—hazard/Peak	918	-	0.014	30
Lithium—RE smoothing	1930	-	0.016	25

The grid includes 25 bus nodes and 43 transmission lines. The data on transmission lines, i.e. length, susceptance and maximum permissible throughput capacity, are confidential and cannot be reproduced here.
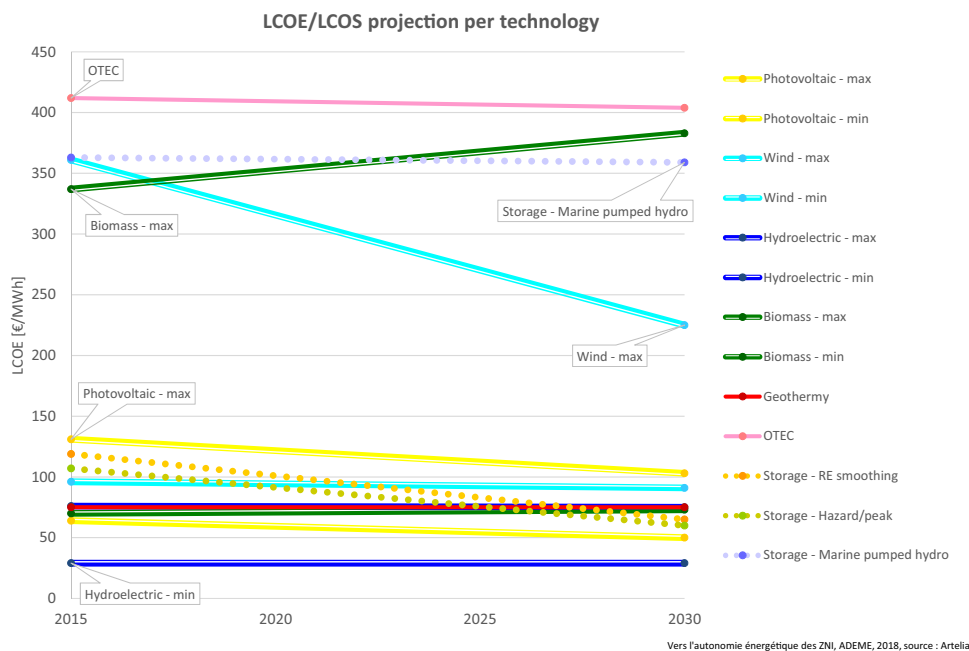
3.3 Evolution of Electricity Demands

The case study covers all electricity demands on the island—all sectors of activity and all uses—including electricity uses for transport. The electricity demand scenario was carried out using MedPro tool[4], a forecasting tool developed by Enerdata, which produces electricity demand projections and associated load curves. MedPro is a bottom-up techno-economic model based on a detailed description of energy consumption and its determinants (e.g. economic growth, population, housing). This model has been calibrated on the prospective scenario "MDE+", which is used to define the official energy policy of the EU[5]. In this scenario, energy demand management is considered. The total demand for electricity is broken down into 12 uses as shown in Fig. 4 for the MDE+ scenario. The demands are then distributed on buses and time slices.

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[4] For information, visit the Enerdata site https://www.enerdata.net/solutions/medpro-medee-model.html

[5] MDE means: *maîtrise de la demande en eńergie*

LCOE/LCOS projection per technology

Total demand reaches 3'313 GWh in 2030 (excluding grid losses), of which 234GWh is for electric mobility. (In this scenario, we assume that electric cars represent 100% of sales in 2030). We assume that 50% of the latter is transferable through demand response mechanisms.

Remark 4 The effect of climate change on cooling demand in the short term (by 2030) has not been explicitly modelled in this study, as we expect it to be of the same order of magnitude as the potential energy savings to be implemented on cooling demand. This assumption should be consolidated by further studies. However, a possible effect of climate change should be taken into account when considering longer timescales.

3.4 Techno-economic Parameters

In Table 1, we report the list of technologies considered in ETEM-SG with cost assumptions and total potentials in 2030.

Remark 5 Table 1 does not include costs related to fossil fuels, such as coal and diesel, since the objective is to get rid of these GHG emitting technologies. The same goes for Fig. 5. By way of comparison, coal-fired power plants had an average cost of energy production (LCOE) of 104 €/MWh

in 2015. The cost of diesel power plants was extremely high due to their very low annual production.

Using these cost parameters, ETEM-SG calculates the overall cost of the energy production system, which depends on the characteristics and resources of each production site. For example, an illustration of the average costs per energy sector is given in Fig. 5. When different technologies exist for the same sector, the envelope cost is presented on the graph (minimum and maximum costs). In 2015, the model reconstitutes a full production cost consistent with that published by the *Commission de régulation de l'énergie (CRE)*[6]. The assumptions used to project the costs of the different technologies are all conservative compared to the various studies in the literature.

Other parameters of the ETEM-SG, e.g. availability factors, efficiencies and availability date, are available in the report [1] for interested readers. Figure 6 gives the nodal residual capacities[7] of the Reference Energy System (RES) in 2015 and the identified RES potentials in 2030, by energy form.

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[6] French Energy Regulatory Commission.

[7] Residual capacities are the installed capacities at the beginning of the planning horizon. These installed capacities remain available for the remaining life of the technologies.

Fig. 6 Nodal residual capacities in 2015 and renewable potentials in 2030
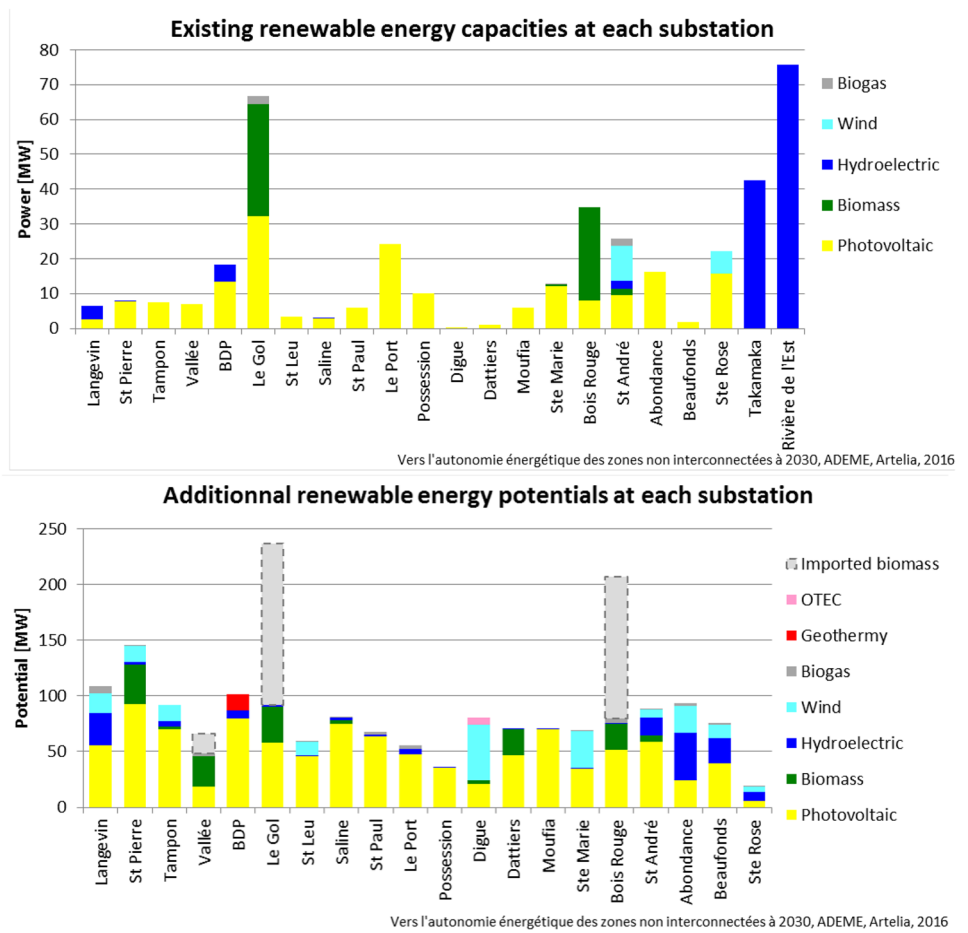

4 Computational Results

This section presents in more detail the computational result for a 100% renewable transition of the electricity sector in *La Réunion*.

We first detail the proposed optimal system using the modelling approaches MedPro and ETEM-SG. We then summarize the results of the static and dynamic analyses. Finally, we report the cost analysis of the transition to a 100% renewable electricity system in 2030.

4.1 Optimal System Evolution

Figure 7 shows the evolution of installed capacity and the energy mix by energy form over the period 2015-2030. It can be seen that the objective of 100% renewable energy is reached in 2030 with significant investments in distributed photovoltaic panels, with a total capacity of 713 MW which represents 60% of its identified potential. Hydroelectric (193MW), biomass (140 MW), bagasse (120 MW) and geothermal (15 MW) sources are exploited to their maximum

Fig. 7 Evolution of the installed capacities (left) and energy mix (right) on the 2015-2030 period
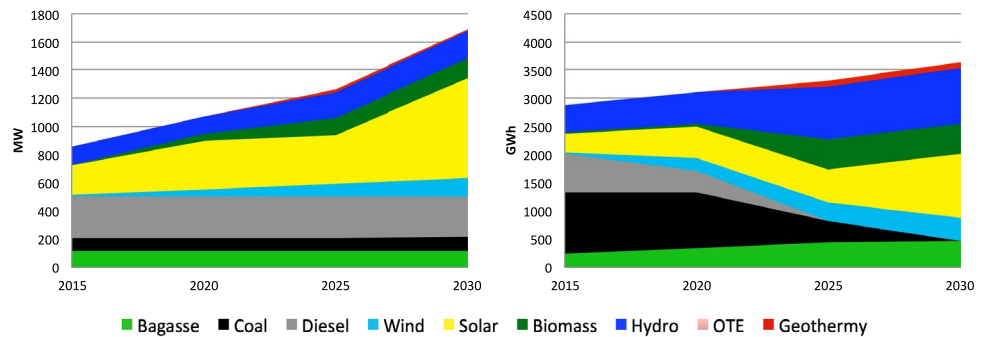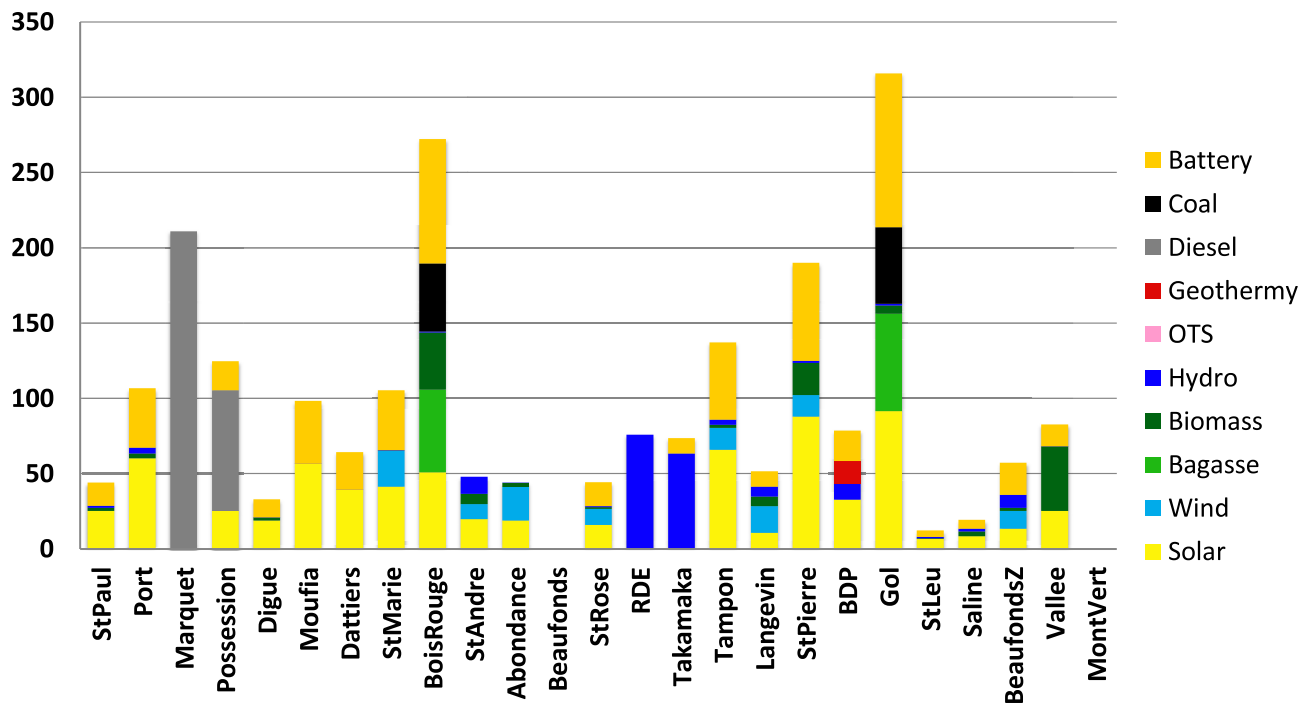
Fig. 8 Installed capacities at each bus in 2030

potential, ensuring stable system production. As for intermittent solar production, onshore wind turbines are not fully exploited and reach in 2030 a capacity of 125 MW (90% of potential). Offshore wind and ocean thermal technologies are not economically competitive enough to be deployed. It should be noted that fossil fuel power plants are no longer used in 2025 for diesel and 2030 for coal. Overall, variable energy sources (photovoltaic, wind and hydro) account for 69% of the energy mix in 2030, much higher than the regulatory limit of 30% in France. Finally, this energy mix leads to two network reinforcements limited to 18 MW, i.e. 7.2 MW on the Abondance-Moufia line and 10.8 MW on the Abondance-Saint André line.

Remark 6 Diesel and coal disappear from the energy mix by 2030. This is a constraint on the optimization model, as the study focuses on the feasibility of a 100% renewable electricity system in 2030.

Figure 8 shows the nodal location of the generation units by energy form. It also shows the storage capacities that provide the system with the necessary reserve to cope with generation intermittency and demand fluctuations. As expected, the low reinforcement of the grid mentioned above is due to the distributed generation throughout the island and in particular near the demand centres. A total of 596 MW of lithium battery capacity is invested to ensure the hourly balance of supply and demand in ETEM-SG on typical days. These reserve capacities make a full dispatch

simulation feasible in 2030. Of these 596 MW of batteries, 340 MW are specifically dedicated to demand variability and 265 MW to intermittent energy.

Remark 7 The proposed approach to moving to 100% renewable energy includes a smart grid component, namely the ability to control the charging of electric vehicles.

Figures 9 and 10 show the load curves calculated by ETEM-SG for each typical day (weekday and weekend, respectively), and for each season. The orange and black lines represent the load curves before and after EV charging control, respectively. Storage occurs when production exceeds demand (the areas under the x-axis) at peak sunlight hours, while discharge, shown in dark yellow, occurs mostly in the evening between 4 and 10 pm. It can be seen that bagasse production only occurs during the sugar industry periods and is mainly replaced by hydroelectric production during the rest of the year.

4.2 Dispatch Simulation in 2030

Figure 11 illustrates the result of the dispatch simulation. It shows a possible hourly contribution of each generation sector over a full year 2030 ensuring hourly supply–demand balance. The energy system resulting from the ETEM-SG and the dispatch simulation shown in Fig. 11 was obtained by iteratively increasing the reserve requirement until dispatch was feasible. This process resulted in a reserve
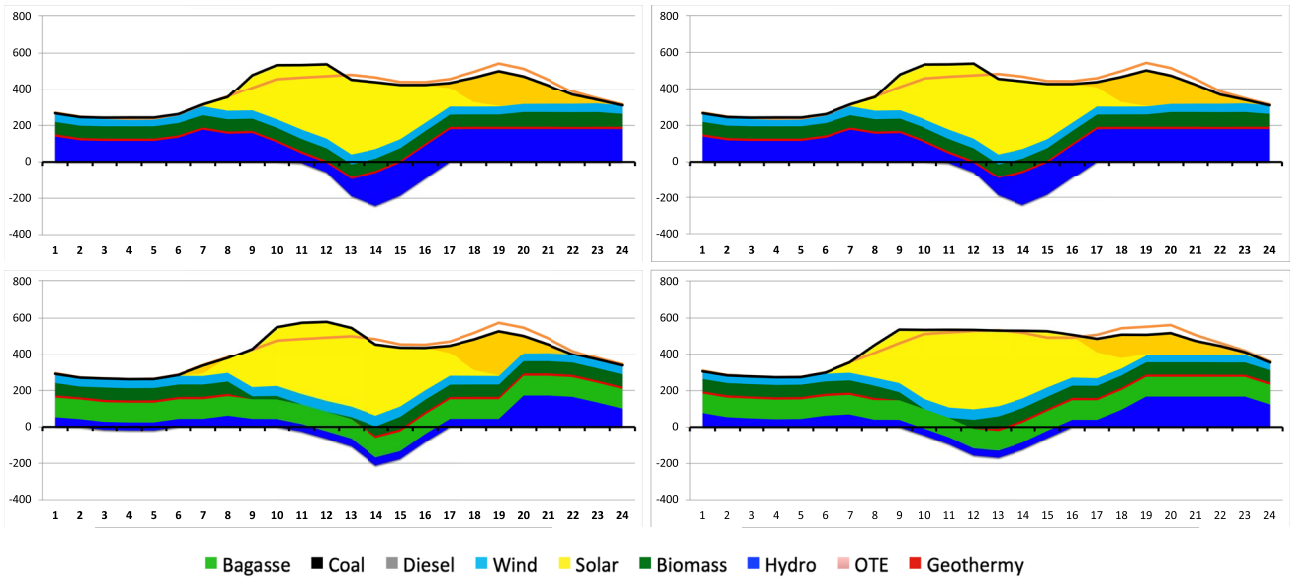
Fig. 9 Hourly load flow for the four week typical days (winter—top left, springer—top right, summer—bottom left, and autumn—bottom right) in MW

requirement of 70% of the variable energy output at any given time. According to ETEM-SG, this time-dependent reserve is provided either by batteries, hydroelectric dams or biomass thermal power plants.

4.3 Implications on System Stability in 2030

Given the large share of variable resources in the generation mix (69%), a static and dynamic validation is necessary to study the behaviour of the power system in case of disruptive events. In this paper, we focus our analysis on three extreme operating situations observed in the dispatch

simulations presented in Fig. 11. In Fig. 12, we display the 8760 operating points according to their production level and VRE rate. We have selected the following three situations as the most critical for the stability of the grid: 1) the lowest decentralized generation rate, 2) the highest annual peak load and 3) the maximum penetration of wind and photovoltaic generation.

Conclusions on the Static Analysis Static studies in PowerFactory have determined the state of the voltage plan at each operating point. This constraint is not taken into account by the ETEM-SG model but is of great importance in the design
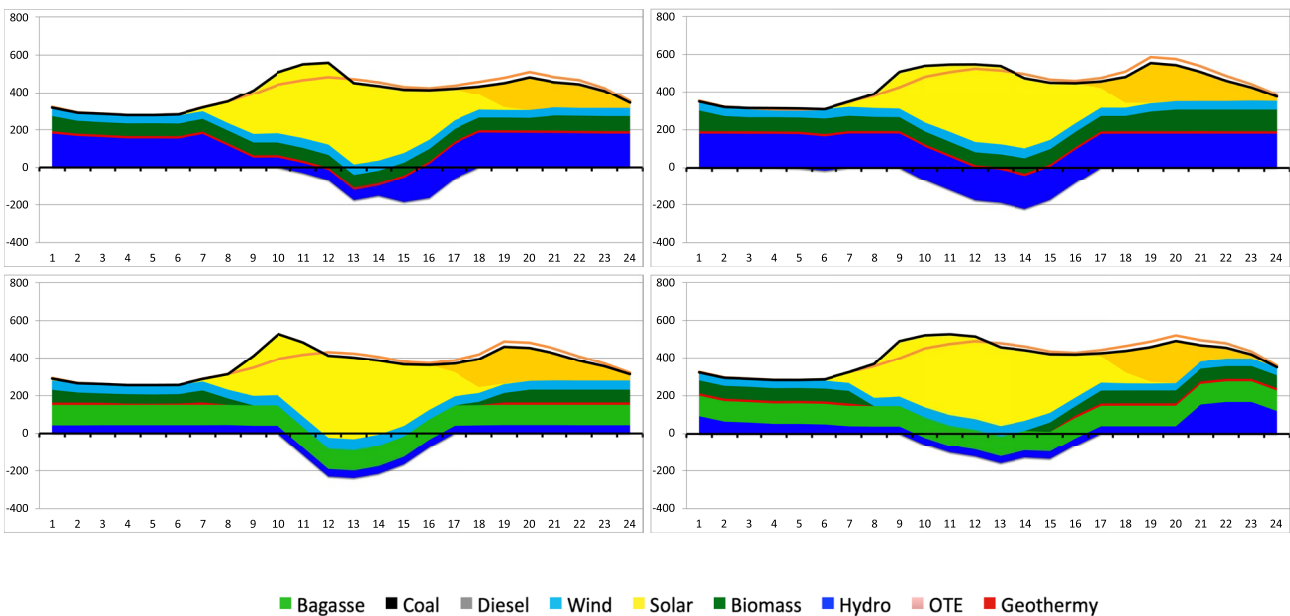
Fig. 10 Hourly load flow for the four weekend typical days (winter—top left, springer—top right, summer—bottom left, and autumn—bottom right) in MW
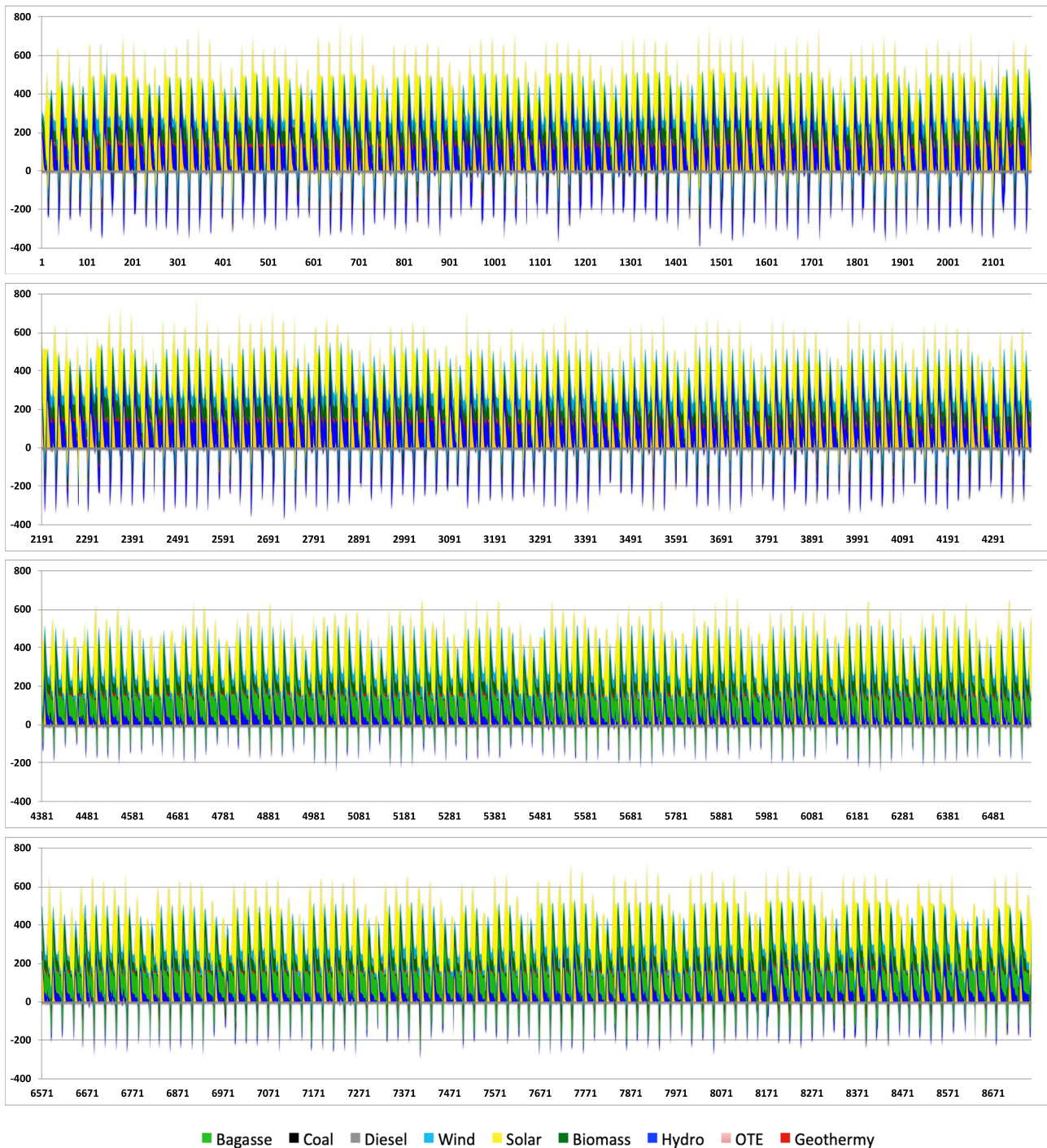
Fig. 11 Hourly load flow from the dispatch model in MW

and operation of power systems. The voltage plan may also require reinforcement of the network if it does not respect the limits defined by the operator, which is not the case here.

Usually, the voltage is controlled by the generators by injecting or absorbing reactive power into the grid. In high distributed generation scenarios, voltage maintenance cannot be ensured by conventional power plants, as they are usually disconnected

at these times. In addition, diffuse PV and wind turbines are connected to the distribution grid and therefore cannot directly regulate the voltage on the grid. In addition, diffuse PV and wind turbines are connected to the distribution grid and therefore cannot directly regulate the voltage on the grid.

Voltage maintenance is therefore essentially ensured by the battery farms, centralized and connected to the source substations by dedicated high-voltage feeders, which allow
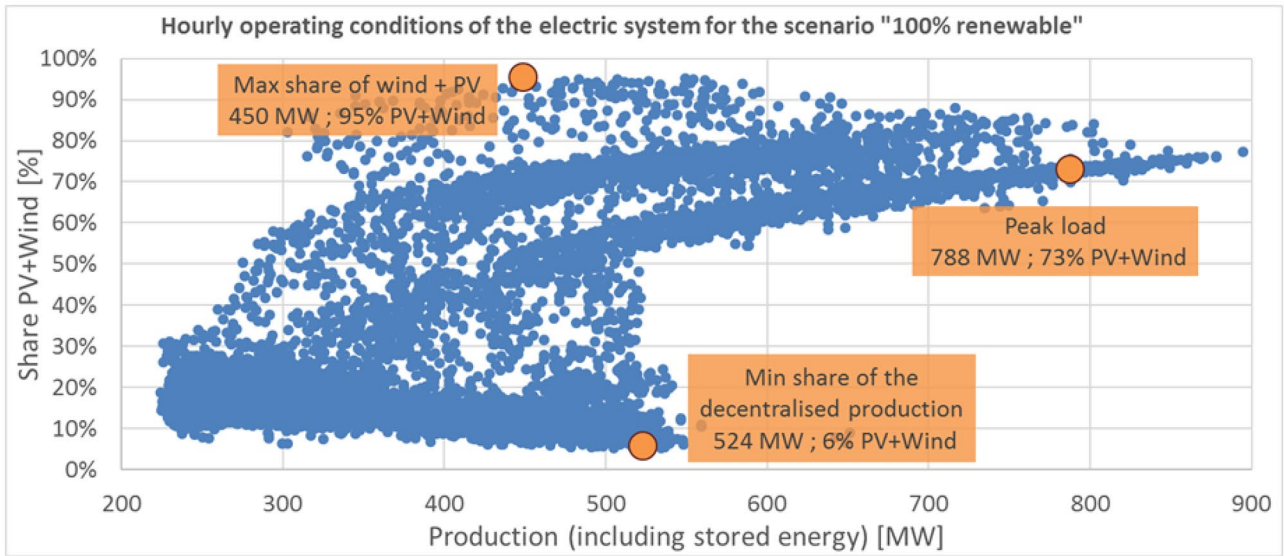
**Fig. 12** Hourly operating management points from dispatch simulation in 2030

the supply and/or absorption of reactive power at any time of the day. It was not necessary to add local reactive compensation (capacitors), although this could be an alternative if the batteries are not sufficient.

It should be noted that these results are highly dependent on the assumptions made regarding the battery farms (centralized connection, cos(ϕ) of 0.9, relatively high installed

power, etc.). Under these assumptions, the voltage plan is maintained within the acceptable range.

Conclusions on the Dynamic Analysis The dynamic stability studies were carried out starting from operating point 3 above (i.e. the lowest decentralized generation rate). It corresponds to a very constraining situation of low power

Fig. 13 Frequency (*Frequence electrique (Hz)*) and voltage (*Tensions (pu)*) curves in case of a voltage drop
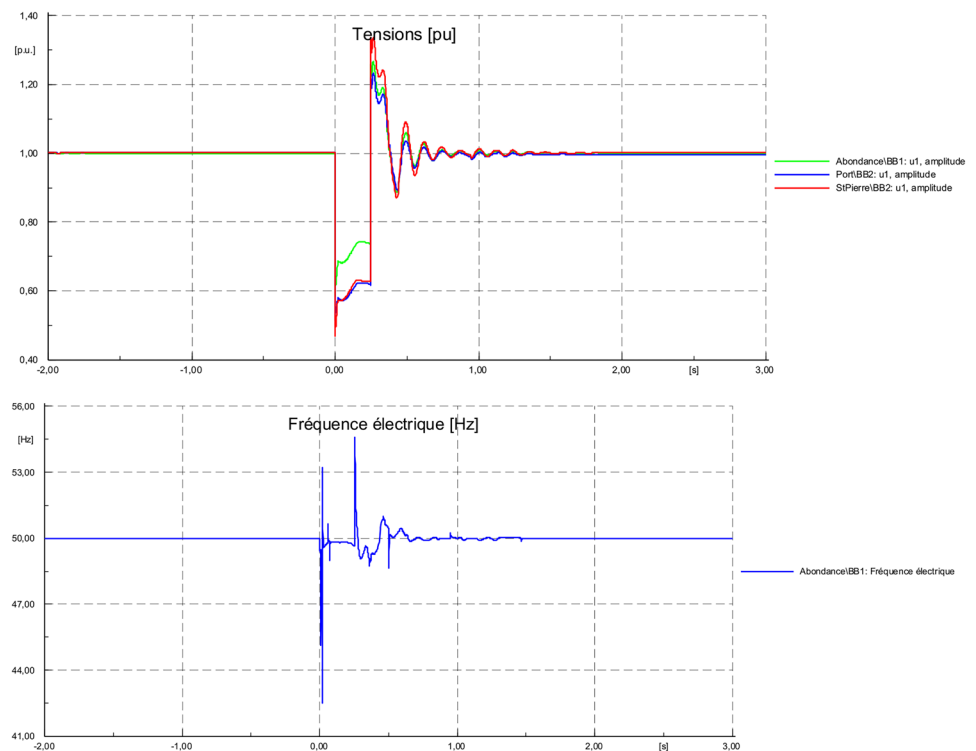
Fig. 14 Frequency (*Frequence electrique (Hz)*) and voltage (*Tensions (pu)*) curves in case of a sudden loss of a 53MW plant at full load
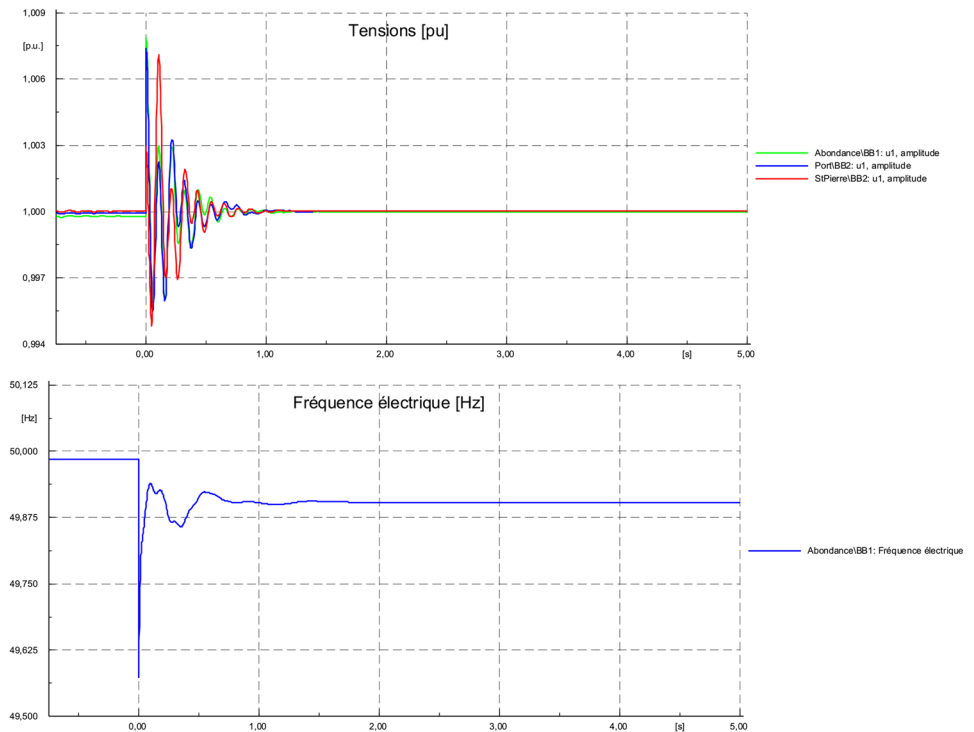
system inertia, low power short circuit and high generation variability.

The results of the following 3 case studies are presented below:

– Case study 1: Voltage drop (short circuit) of 250 ms on the busiest line (Gol-Saline) and then elimination of the fault by opening of the circuit breakers;
– Case study 2: Sudden loss of a 53MW plant at full load;
– Case Study 3: Sudden loss of the entire PV injection at the Le Gol bus node.

For these three events, despite the very low inertia of the power system, resulting in a rapid variation of its frequency, the dynamic stability of the system is ensured by the very fast response time of the batteries. Such an electrical system can therefore remain stable in the face of major incidents. However, due to the simplifying assumptions made in the modelling of the grid, this result, although encouraging, does not allow us to conclude that the real system is stable and safe under all operating conditions.

As an illustration, Fig. 13 shows some network frequency and voltage curves for the case study 1.
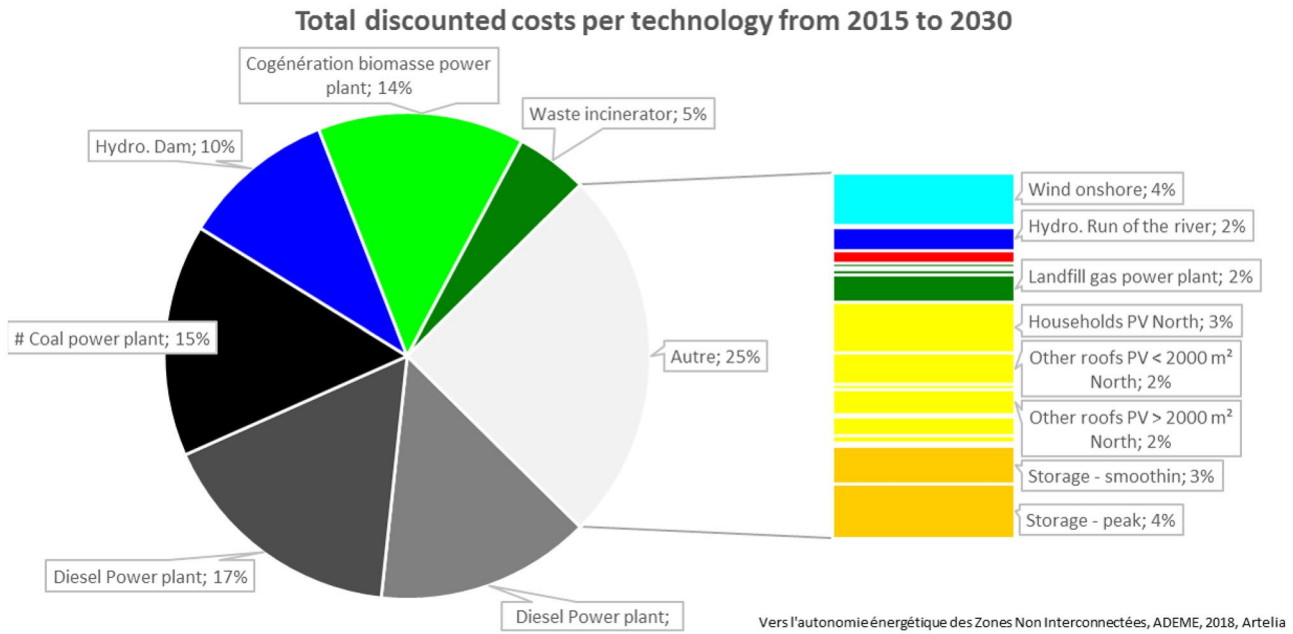
A rapid return to stability is observed, in less than two seconds after the fault has been cleared. This is faster than what is observed today (usually several seconds or tens of seconds) and is mainly due to the high reactivity of the power electronics-based interfaces.

During the fault period (250 ms), the voltage on the whole network drops. Dynamic voltage support is mainly provided by the centralized ground-mounted PV and storage batteries, connected to the high-voltage grid or dedicated medium-voltage outputs, whose reactive power injection maintains the voltage.

However, the short-circuit power at the fault is very low compared to standard values. This confirms that the very high penetration rates of inverter-interfaced generation can pose problems related to fault detection and thus to their adequate elimination. In addition to imposing strict operating constraints on diffuse installations, in such a context it

Table 2 Economic results

On the 2015-2030 period	
Total discounted cost	5659 M€
Investment cost	2579 M€
Reinforcement cost	1.5 M€
On the equipment lifetime	
Average LCOE	126 €/MWh
Average LCOE for new units	100 €/MWh
Median LCOE	88 €/MWh
Marginal costs in 2030	
Average marginal cost	176 €/MWh
Maximum marginal cost	1378 €/MWh
Minimum marginal cost	0 €/MWh

Total discounted costs per technology from 2015 to 2030

Cogénération biomasse power plant; 14%

Waste incinerator; 5%

Hydro. Dam; 10%

Wind onshore; 4%

Hydro. Run of the river; 2%

Landfill gas power plant; 2%

Coal power plant; 15%

Households PV North; 3%

Other roofs PV < 2000 m² North; 2%

Other roofs PV > 2000 m² North; 2%

Autre; 25%

Storage - smoothin; 3%

Storage - peak; 4%

Diesel Power plant; 17%

Diesel Power plant;

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Fig. 15 Repartition of total discounted costs on the 2015-2030 period
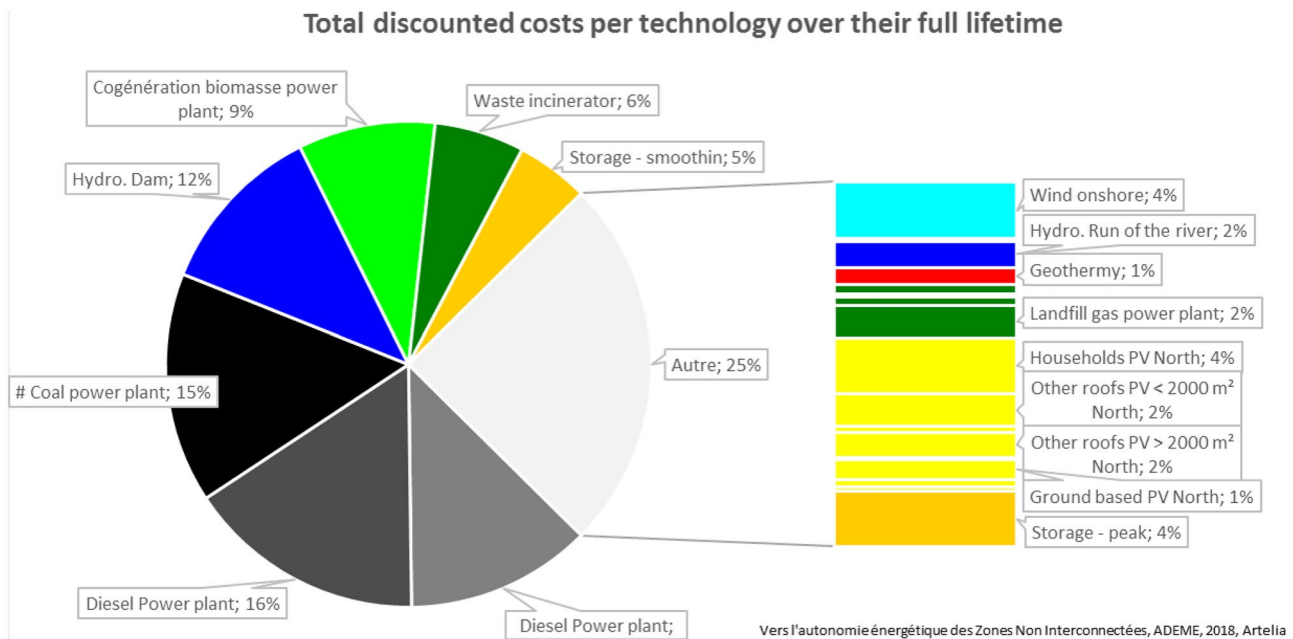
would probably be necessary to modify or even completely rethink the network protection schemes.

As an illustration, Fig. 14 shows some curves of frequencies and voltages of the network for the case study 2, i.e. sudden loss of a power plant at full load. The results for the case study 3 are similar.

The different quantities observed return to stability very quickly in less than two seconds after the generator loss is triggered. Given the small proportion of rotating machines

connected, the rotating reserve is almost zero in this scenario and most of the power reserve mobilized comes from the batteries.

The batteries react quickly to the observed frequency deviation. It is important to note that the drop in frequency response is very rapid after the generator is tripped. This is due to the very low inertia of the electrical system. The performance of the frequency control by the batteries is therefore fundamental for maintaining the stability of the system.

Total discounted costs per technology over their full lifetime

Cogénération biomasse power plant; 9%

Waste incinerator; 6%

Storage - smoothin; 5%

Hydro. Dam; 12%

Wind onshore; 4%

Hydro. Run of the river; 2%

Geothermy; 1%

Landfill gas power plant; 2%

Coal power plant; 15%

Households PV North; 4%

Other roofs PV < 2000 m² North; 2%

Other roofs PV > 2000 m² North; 2%

Autre; 25%

Ground based PV North; 1%

Storage - peak; 4%

Diesel Power plant; 16%

Diesel Power plant;

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Fig. 16 Repartition of total discounted costs on the equipment life duration

The high installed power of the batteries, under the parameter assumptions considered, allows the system to maintain a small static difference after frequency stabilization (of the order of 100 mHz). The frequency therefore remains in the range [48-52 Hz] which corresponds to the normal operating range of the system in all the cases studied. The load shedding thresholds are therefore not exceeded in the cases studied, which minimizes the undistributed energy.

4.4 Cost Analysis

The economic indicators obtained are summarized in Table 2. In this scenario, fossil power plants are completely replaced by renewable energy in 2030. The two energy storage technologies together account for most of the cost of energy in 2030. It should be noted that the weight of storage to regulate renewable energy production is equivalent to that of covering contingencies and peak demand, with, respectively, 12% and 11% of costs. After storage, the sector that weighs the most on the complete cost of production remains a sector using a fuel (biomass cogeneration) with 14% of costs, followed by the hydro-electric dam and the incinerator.

As shown in Figs. 15 and 16, the most important items of discounted costs for the 2015-2030 period are the three fossil-fuelled plants (oil combustion turbines, coal-fired power plants, diesel plants) and cogeneration biomass plant.

5 Conclusion

In this paper, one has described a comprehensive three-level approach to designing the energy transition to 100% renewable electricity generation in non-interconnected areas. First, the ETEM-SG capacity expansion model is used to determine an optimal investment plan, based on typical days, over the whole transition period 2015-2030. Then, a dispatch model simulates and validates the supply–demand balance over a full year and proposes a reserve adjustment if necessary. Finally, static and dynamic studies are carried out on the most critical situations of the dispatch simulations for extreme events impacting the stability of the voltage and frequency network. The approach has been validated and used for several isolated French territories, islands or remote areas.

The application to the case study Reunion leads to the following conclusions. Firstly, we note that the local renewable potentials are sufficient to ensure a 100% renewable and local electricity mix while satisfying at all times the supply–demand balance on an hourly basis for a full year with representative meteorological time series. This requires a significant investment in storage capacity. Secondly, existing diesel plants would no longer be competitive with renewables by 2025, even taking into account the system services they provide. Specifically, the variable costs of diesel units would already be higher than the total costs of competitive renewable energy technologies. The decommissioning of conventional power plants will have a significant effect on the inertia of the electricity system. This has been addressed in our analysis.

Finally, the results of the static and dynamic simulations do not show any divergence of the main electromechanical quantities of the network (frequency, voltage, current, etc.) for the cases tested. The power system can therefore remain stable in the face of such major incidents, under the somewhat simplifying assumptions made. It is therefore important to remember the importance of the modelling assumptions in the static and dynamic analysis. Any change in these assumptions, particularly with regard to the installed powers and equipment parameters represented in the power system model, could affect the conclusions. In particular, the simulations carried out in this study only concern the high-voltage network since in the power system model it has been considered that decentralized generation units, such as plug-in hybrid electric vehicles (PHEVs), will not participate in the power supply, nor in the reactive power compensation. Therefore, they do not participate in the voltage adjustment of the 63 kV grid. In practice, these devices could be involved in voltage control on the distribution networks, but this would have little influence on the high-voltage network.

Declarations

Conflicts of Interest Not applicable

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