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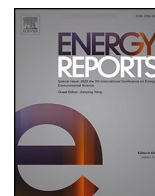
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Research paper

Future energy scenarios with renewables and flexibilities in distribution grids – National case study in France

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ABSTRACT

Medium and low voltage distribution grids are at the core of the energy transition as they are expected to host a large share of renewables and flexible resources. Their modeling within decarbonization pathways is then of great importance in providing realistic future energy scenarios. This paper investigates different scenarios at the French national scale up to 2050 while varying the electricity demand, renewables installed in both transmission and distribution grids, and the considered flexibility technologies. The methodology relies on coupling a long-term energy model (POLES) and an open-source short-term optimization framework (Backbone). POLES produces long-term decarbonization scenarios, while Backbone enables the optimization of the power system. Technical and financial impacts are studied through ten scenarios regarding produced energy, installed capacities, and investment costs. The results highlight the importance of the load demand modeling assumptions, even raising the question of the feasibility of high-demand scenarios. Also, results show that demand-side flexibility can significantly reduce the requirements in conventional storage technologies (up to 98%). Distributed flexibilities, such as electric vehicle smart charging, are especially effective. Considering multiple types of distribution grids allows, in the end, to show that installing renewable generation at the transmission or distribution level only moderately influences global costs, with a minor advantage for centralization to limit reverse flows on transformers. The paper concludes with a comparison with other scenarios (drawn from up-to-date literature) and a discussion of the environmental footprint of these scenarios, both in terms of mineral resource consumption (raw materials) and land footprint.

1. Introduction

Carbon emissions reduction is necessary to limit climate change (Calvin et al., 2023). To that end, one of the main strategies proposed at the global scale is the electrification of energy usage, such as transportation, together with the replacement of fossil fuels with renewables (Cozzi et al., 2024). Improving energy efficiency and sufficiency are strong levers to act on power consumption up to 2050 and effectively diminish fossil fuel demand (Cordroch et al., 2022).

With the growing importance of electricity, prospective studies are performed to propose relevant energy scenarios for large power systems. Long-term models are conventionally used to guide policymakers in their decisions on decarbonization pathways, thanks to the comprehensive view of the energy sector provided by these models, generally relying on a large geographical and temporal granularity of power

systems. Power systems are key to the energy transition to enable the transmission of variable renewable energy (VRE) power to consumers (International Energy Agency, 2023). Therefore, their representation in long-term models is relevant (Després et al., 2015), but these models cannot consider subnational geographical resolution. As such, power grid analysis requires dedicated modeling tools, which can be coupled with long-term models (Allard et al., 2020b).

Recently, long-term studies considering transmission grids at the European level (Hörsch et al., 2018), (ENTSO-E, 2025) and the national level (RTE, 2022) were conducted. They highlighted the transmission grid's role in the energy transition to ensure the power transmission between regions with complementary renewable production. However, distribution grids, which represent the majority of the total grid length (95%) and also host most of the VRE capacity (70%) in Europe (Eurelectric, 2024), are rarely considered in decarbonization pathways. Their transformation is envisioned, nonetheless, as in (ENEDIS, 2021)

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Nomenclature			
Sets			
$l \in L$	Set of lines	η_u	Storage efficiency
$n \in N$	Set of nodes	η_l	Line losses factor
$t \in T$	Set of timesteps	π_u^{cap}	Unit investment cost (€/MW)
$u \in U$	Set of units	π_l^{cap}	Line investment cost (€/MVA)
		π_u^{gen}	Operational cost (€/MWh)
		π^{flex}	Flexibility cost (€/MWh)
Subsets		Variables	
$in(n) \subset L$	Lines to node n	$e_{n,u,t}$	Energy stored (MWh)
$out(n) \subset L$	Lines from node n	$f_{l,t}$	Power flow (MW)
$N^{hv}/N^{mv} \subset N$	HV/MV grid nodes	f_l^{cap}	Line capacity investment (MVA)
$U^{vre} \subset U$	Renewable units	$p_{n,u}^{cap}$	Capacity investment (MW)
$U^{sto} \subset U$	Storage units	$p_{n,u,t}^{ch}$	Battery charging power (MW)
$U^{th} \subset U$	Thermal units	$p_{n,u,t}^{disc}$	Battery discharging power (MW)
		$p_{n,t}^{ev+}/p_{n,t}^{ev-}$	EV load increase/decrease (MW)
Parameters		$p_{n,t}^{h2+}/p_{n,t}^{h2-}$	Electrolyzer load increase/decrease (MW)
$E_{n,u}^{cap0}$	Storage capacity (MWh)	$p_{n,t}^{ind+}/p_{n,t}^{ind-}$	Industrial load increase/decrease (MW)
$p_{n,u}^{cap0}$	Nodal installed capacity (MW)	$p_{n,u,t}^{gen}$	Power generation (MW)
$p_{n,mv}^{cap, ev0}$	EV charger initial capacity (MW)	p^{flex}	Flexibility cost
$p_{n,hv}^{cap, h20}$	Electrolyzer initial capacity (MW)	LRE	Grids with a low share of renewables
$p_n^{cap, ind0}$	Industrial capacity for flexibility (MW)	MV	Medium voltage
$p_{n,t}^{dwh0}$	Water heating load (MW)	PSH	Pumped-storage hydroelectricity
$p_{n,t}^{ev0}$	EV charging initial load (MW)	PV	Photovoltaic solar
$p_{n,t}^{h20}$	Electrolyzer initial load (MW)	VRE	Variable renewable energy
$p_{n,t}^{ind0}$	Industrial initial load (MW)	Glossary	
$p_{n,t}^{load}$	Nodal power demand (MW)	BESS	battery energy storage systems
$p_{n,t}^{load, remain}$	Remaining load (MW)	DSM	Demand side management
p_u^{POLES}	New capacity to install (MW)	EV	Electric vehicle
α	Share of capacity installed in MV	HRE	Grids with a high share of renewables
Δt	Timestep duration (h)	HV	High voltage
$\lambda_{n,mv,t}$	Share of EV connected to the grid		

and (Abdelouadoud and Girard, 2025), but a posteriori. Distribution grids are thus considered after determining decarbonization pathways. The question of the best decarbonization pathways for distribution grids is then overlooked, leading to less efficient/realistic strategies. The choice of future power systems will impact economic (RTE, 2022) and environmental costs (Brugger et al., 2021). However, even if there is a clear objective of reaching net-zero carbon emissions by 2050 in Europe, the proposed pathways have diverse power consumption by 2050 (Tsiropoulos et al., 2020). Providing a more precise assessment of these impacts, with the modeling of the whole grid instead of only the transmission grid, is crucial.

Although the increase in power consumption is a major driver for power grid reinforcement, the large integration of distributed power generation also incurs challenges for the grids, with higher strain on lines and transformers (ENEDIS, 2021). VRE installation can be highly centralized to reach several tens of MW. In such cases, VRE are connected to the transmission grid, thus preserving a vertical grid architecture with unidirectional power flows from the high voltage grids down to the end-users. On the contrary, distributed VRE decentralizes production capacities closer to the point of delivery, reducing Joule losses (Adefarati and Bansal, 2016) at the cost of potential bidirectional power flows at the interface between transmission and distribution grids. The choice between centralized and decentralized VRE resulted in a slightly lower cost for decentralized production in Germany notably with lower transmission grid investments (Kendziorski et al., 2022), but (Tröndle et al., 2020) concluded that at the European level, centralizing VRE could reduce by 20 % the power system cost even if a stronger transmission grid was required. These two studies considered only the

transmission grid, so adding distribution grids should offer a more comprehensive view of the question. Scenarios considering variations in consumption profiles and VRE distributions have already been studied (Veldman et al., 2013). However, they did not differentiate the two aspects and only represented residential distribution grids.

To limit the grid reinforcement due to higher electrification, flexibility options can be used (Gupta et al., 2021). Flexibility, as defined by (Lechl et al., 2023), is the ability to balance the disequilibrium between the load and actual generation with systems that modulate their operating power. This definition covers a wide range of actions, from very short-term inertia issues to seasonal storage (Clerjon, 2021). However, most studies consider only medium-term flexibility, i.e. hourly power load shifted along a day. This type of flexibility can typically be provided by batteries (Resch et al., 2021) and/or demand side management (Dranka et al., 2021), such as from the control of electric vehicles (EV) charging (Aliasghari et al., 2025), heating (McGarry et al., 2024), or water electrolysis for hydrogen production (Lange et al., 2023). The capability of other demand sectors to provide flexibility is investigated (e.g., datacenters in (Takci et al., 2025)), but remains marginal compared to the ones presented before.

Several studies highlighted the compromise between grid enhancement and flexibility installations. Both (Brown et al., 2018) and (Rinaldi et al., 2022) have shown, respectively, on transmission and distribution grids, that a stronger grid reduces the storage capacity needs, due to increased energy transport capacity. Indeed, a stronger grid enables the balance of power between more geographically distant producers and consumers, thus reducing the demand for local flexibility. In a 100 % renewable context, (Steinke et al., 2013) evaluated the cost of several

Table 1
Scales and flexibilities in long-term decarbonization studies in the literature.

Study	Systemic	Distribution grids	EV flexibility	Industrial flexibility	Electrolyzer flexibility	Tradeoff local vs centralized VREs
Our study	✓	✓	✓	✓	✓	x
(Hörsch et al., 2018)	✓	x	x	x	x	x
(ENTSO-E, 2025)	✓	x	x	x	x	x
(RTE, 2022)	✓	x	✓	✓	✓	~
(ENEDIS, 2021)	x	✓	✓	x	x	x
(Brugger et al., 2021)	✓	x	x	x	x	x
(Abdelouadoud and Girard, 2025)	x	✓	x	x	x	x
(Tsiropoulos et al., 2020)	✓	x	x	x	x	x
(Kendziorowski et al., 2022)	✓	x	✓	✓	x	✓
(Tröndle et al., 2020)	✓	x	x	x	x	✓
(Veldman et al., 2013)	x	✓	✓	x	x	✓
(Gupta et al., 2021)	x	✓	✓	x	x	x
(Dranka et al., 2021)	✓	x	x	✓	x	x
(Aliasghari et al., 2025)	✓	x	✓	x	x	x
(McGarry et al., 2024)	x	✓	✓	x	x	x
(Brown et al., 2018)	✓	x	✓	x	x	x
(Rinaldi et al., 2022)	x	✓	x	x	x	x
(Steinke et al., 2013)	✓	x	x	x	✓	x
(Valkering et al., 2023)	✓	✓	✓	x	x	x
(Algburi et al., 2025)	✓	x	✓	x	x	x
(Bagherzadeh et al., 2024)	x	✓	✓	x	x	x
(Allard et al., 2020a)	✓	✓	x	x	x	x
(Jacquier et al., 2025)	✓	✓	x	x	x	x

storage and grid reinforcement rates, but the storage types were considered separately (no synergies). (Valkering et al., 2023) demonstrated the role of EV flexibility in reducing system costs but only considered solar generation for renewable sources. EV flexibility is also highlighted as a promising source of flexibility to reduce grid investments in (Algburi et al., 2025). Flexible energy hubs with renewables in (Bagherzadeh et al., 2024) are also a solution to help reduce the grid operation cost. Overall, these studies capture only part of the problem. A systemic view is lacking to enhance the knowledge on this topic.

In previous studies, (Allard et al., 2020a) initiated actions to consider distribution grids in the long-term planning of large energy systems. However, their model represents a limited number of distribution grids while the transmission system was simulated at the European level. The limited number of distribution grids diluted in this extensive spatial coverage prevents the study of the systemic impacts of distribution grids. In further studies (Jacquier et al., 2025), a new model that enables the study of distribution grids at a national level was developed to increase the relevance of the results. This method, based on a coupling of a long-term and a short-term energy model, is used in this paper to study decarbonization strategies under several scenarios. This enables the comparison of various decarbonization pathways considering transmission grids and different types of distribution grids (urban and rural types, with a focus on medium-voltage distribution grids). This fills the

gap in the literature, in which the distribution grid's role in decarbonization pathways is overlooked, as shown in Table 1. Based on the methodology described in (Jacquier et al., 2025), this paper studies scenarios that envision different power demands and distributions of VRE in France up to 2050. Then, the flexibility modeling is detailed for water heating, EV, and industrial demand management, subdivided into electrolysis and non-electrolysis activities, to study their impacts on each other, and the battery and grid reinforcement requirements.

The main contributions of the paper are listed below:

- Modeling of decarbonization pathways accounting for the short-term operation of renewables and flexibilities in different types of distribution grids;
- Ten scenarios were investigated with several consumption levels, locations of renewables, and flexibility technologies;
- Assessment of installed capacities, investment costs, grid impacts, as well as material and spatial requirements for most studied scenarios.

The paper is organized as follows: Section 2 presents the models, notably of the flexibilities. Section 3 presents the scenarios studied in this article. Section 4 highlights the consequences of the considered scenarios on the power system with the underlying costs. Finally, some environmental implications of the results are discussed in Section 5, both regarding raw material consumption and land footprint.

Table 2
Scenarios of the study. Flexibility considered are: electrolyzers (EZ), electric vehicles (EV), and HV or MV industrial loads with demand-side management capabilities.

Scenario	Electricity demand in 2050	VRE in distribution grids	Flexibility Considered			
			EZ	EV	HV Indus.	MV Indus.
S1	Low	Medium				
S2	Medium	Low				
S3	Medium	Medium				
S4	Medium	High				
S5	High	Medium				
S6	Medium	Medium	✓			
S7	Medium	Medium	✓	✓ (25 %)		
S8	Medium	Medium	✓	✓ (50 %)		
S9	Medium	Medium	✓	✓ (50 %)	✓	
S10	Medium	Medium	✓	✓ (50 %)	✓	✓

2. Methodology

2.1. Coupling of long-term and short-term models

This work builds upon previous research (Jacquier et al., 2025), which coupled the long-term global partial equilibrium model POLES (European Commission, 2017) and the open-source short-term optimization model Backbone (Helistö et al., 2019). POLES aims at building decarbonization scenarios through its representation of the global (national in this paper) energy needs. This model helps to understand the impact of assumptions and policies on the outcomes. Backbone performs optimization for hourly dispatch and investment problems at the national scale for six representative days. Backbone embeds a formulation in GAMS, which is solved with the CPLEX solver. POLES models the whole energy system (one node per country at the European scale), while Backbone models the distribution and transmission grids with a sub-regional spatial resolution. These two models interact yearly (from 2024 to 2050) to refine POLES calculations with Backbone optimization results (Fig. 1). The optimization problem is then run 27 times per scenario (one time per simulation year). It can be noted that the demand scenarios are given as input to POLES to modify some of its parameters. POLES provides the capacity installed for each technology at a national scale, and Backbone dispatches these capacities in grids and also handles flexibility investments. Indeed, its finer representation of the technical constraints is more suited to estimate the flexibility needs. Consequently, Backbone needs to provide POLES with the capacity it installed in a given year so that POLES can adapt its investments for the following year.

The grid model used in Backbone covers France and is composed of a 14-node transmission grid with three distribution grids per transmission node. In each region, two distribution grids are from the rural type and one from the urban type. Having two rural grids in each region allows the representation of the uneven repartition of VRE (in France, one-quarter of distribution grids host eighty percent of the VRE in 2022

(ENEDIS, 2023)). To that end, one rural distribution grid hosts twice as much VRE as the other rural grid, respectively named HRE-grid (for high renewables) and LRE-grid (for low renewables). The rural and urban grid topologies in this research are chosen among distribution grid data from (Abdelouadoud et al., 2023). In total, 1862 distribution grid nodes are represented: 14 regions with one urban grid of 29 nodes and two rural grids of 52 nodes. Only medium voltage (MV) distribution grids are modeled, as considering low voltage grids would lead to untractable computation time. Modeling only France and not Europe could be seen as a limitation, as some models consider the transmission grid of the entire Europe (Aliasghari et al., 2025). However, these models do not consider the distribution grids, as it is infeasible at the European scale due to intractable computation times (Jacquier et al., 2025). This computation time constraint also limits the temporal resolution that can be considered. Therefore, this work is limited to hourly timesteps, preventing the study of shorter-term issues, such as stability and inertia (Mehrzaad et al., 2026). Indeed, considering inertia in long-term decarbonization pathways is a research subject on its own (Carlini et al., 2021) and would require timesteps of few seconds (number of variables multiplied by 3600) (Bastiani and Oliveira, 2023).

2.1.1. Flexibility modeling

The optimization model is based on four main sets: the time (set $t \in T$, with Δt the timestep duration), the units ($u \in U$) for 30 different technologies (subsets for VRE: U^{vre} , storage: U^{sto} , and thermal: U^{th} with $U = U^{th} \cup U^{sto} \cup U^{vre}$), the nodes ($n \in N = N^{hv} \cup N^{mv}$), which can refer to medium voltage distribution grids ($n^{mv} \in N^{mv}$) or high-voltage (HV) transmission grid ($n^{hv} \in N^{hv}$), and the lines between nodes ($l \in L$). Note that only battery energy storage systems (BESS) and pumped-storage hydroelectricity (PSH) are considered storage units. Furthermore, units are only considered as power sources with some generation constraints, without the amount of technical details that can be found in literature (e.g., (Ahmadianfar et al., 2021)). The objective of the optimization problem (1) is to minimize the overall system cost. It includes

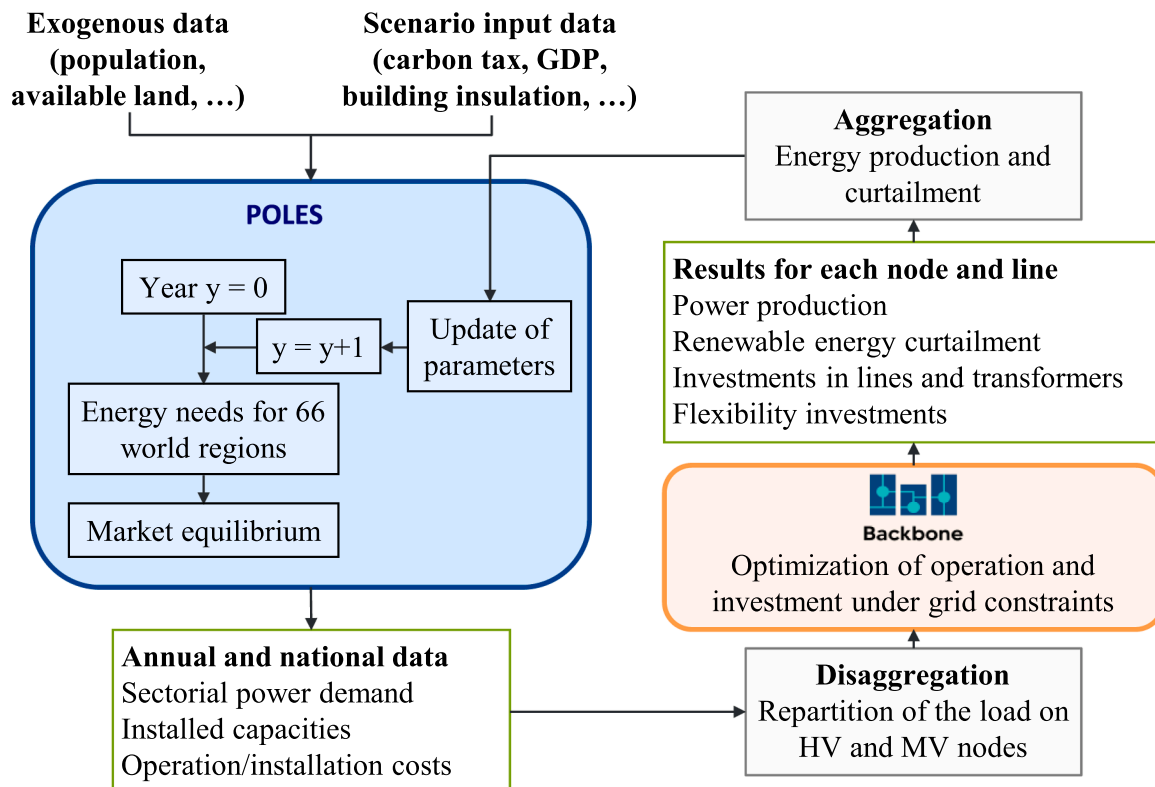


Fig. 1. POLES and Backbone models yearly coupling.

the operating expenditure of units (with $p_{n,u,t}^{gen}$ being the power production), the investment in line capacity (p_l^{cap}), the investment of new VRE and BESS ($p_{n,u}^{cap}$), and the cost of the demand side flexibility (p^{flex}), which is detailed in the following. The arbitrage is driven by the operational cost (π_u^{gen}), the investment cost for capacities (π_u^{cap}) and lines (π_l^{cap}), with costs mainly coming from POLES. Note that grid cost is driven only by the reinforcement of lines and transformers, other costs related to the grid, often displayed in the decarbonization pathways (e.g. (RTE, 2022)), such as the renewal of end-of-life cable, are not part of this objective function.

$$\begin{aligned}
 obj = & \underbrace{\sum_{n \in N} \sum_{u \in U} \sum_{t \in T} p_{n,u,t}^{gen} \times \pi_u^{gen} \times \Delta t}_{\text{operating cost of generation and storage}} + \underbrace{\sum_{l \in L} p_l^{cap} \times \pi_l^{cap}}_{\text{cost of grid reinforcement}} \\
 & + \underbrace{\sum_{n \in N} \sum_{u \in U^{vre} \cup U^{sto}} p_{n,u}^{cap} \times \pi_u^{cap}}_{\text{cost of VRE and BESS installed capacities}} + \underbrace{p^{flex}}_{\text{demand flexibility cost}} \quad (1) \\
 & \underbrace{\sum_{l \in in(n) \subset L} (f_{l,t} \times \eta_l)}_{\text{import/export balance}} - \underbrace{\sum_{l \in out(n) \subset L} f_{l,t}}_{\text{nodal load}} = p_{n,t}^{load} + \sum_{u \in U^{sto}} p_{n,u,t}^{ch} \\
 & - \underbrace{\sum_{u \in U^{th} \cup U^{vre}} p_{n,u,t}^{gen}}_{\text{nodal generation}} - \sum_{u \in U^{sto}} p_{n,u,t}^{disc} \quad \forall n \\
 & \in N, t \in T \quad (2)
 \end{aligned}$$

A power balance (2) is required at each node to equilibrate the power load ($p_{n,t}^{load}$), the power generation from production ($p_{n,u,t}^{gen}$) and storage units ($p_{n,u,t}^{disc}$), the charge of storage ($p_{n,u,t}^{ch}$) and the power exchanges with neighboring nodes ($f_{l,t}$), considering a loss factor in lines (η_l). A distinction is made between power flows in lines coming to a given node ($l \in in(n)$) and the departing lines ($l \in out(n)$). Note that even if the model with distribution grids is focused on France, the model is run once with only the transmission grid, but at the European scale to define the power exchanges of France with the neighboring countries. These power exchanges are then used as inputs of the model with only France and the distribution grids. The demand levels studied in the scenarios have a major impact on this equilibrium as $p_{n,t}^{load}$ varies between scenarios. The load is subdivided in sectors to enable the modeling of demand modulation, as detailed later in Eq. (7).

Another dimension studied in the scenarios is the variation of the VRE percentage installed in distribution grids. POLES defines the quantity of VREs to install (p_u^{POLES}) during its simulations. In the optimization, and especially in Eq. (3), this capacity cannot be installed

$$\begin{aligned}
 \underbrace{p_{n,t}^{load}}_{\text{nodal load}} = & \underbrace{p_{n,t}^{ev0} + p_{n,t}^{ev+} - p_{n,t}^{ev-}}_{\text{EV load}} + \underbrace{p_{n,t}^{h20} + p_{n,t}^{h2+} - p_{n,t}^{h2-}}_{\text{electrolyzer load}} + \underbrace{p_{n,t}^{ind0} + p_{n,t}^{ind+} - p_{n,t}^{ind-}}_{\text{industrial load}} + \underbrace{p_{n,t}^{dwh0}}_{\text{water heating load}} + \underbrace{p_{n,t}^{load_remain}}_{\text{remaining load}} \quad (7) \\
 \forall n \in N, t \in T
 \end{aligned}$$

freely on the different grids, as a share α of the capacity should be installed in distribution grids. The complement is considered to be installed at the transmission level.

$$\sum_{n^{mv} \in N^{mv}} p_{n^{mv},u}^{cap} = \alpha p_u^{POLES} \quad \forall u \in U^{vre} \quad (3)$$

Finally, storage (BESS, PSH) is an important feature in this study, as it is compared with other types of flexibility. The operation of storage accounts for charging ($p_{n,u,t}^{ch}$) and discharging ($p_{n,u,t}^{disc}$) powers that are limited by the existing ($p_{n,u}^{cap0}$) and installed capacities ($p_{n,u}^{cap}$) in Eq. (4).

The stored energy ($e_{n,u,t}$) is also limited, in Eq. (5), with the existing ($E_{n,u}^{cap0}$) and installed energy storage. Note that POLES considers only four-hour duration batteries (e.g., 1 MW/4 MWh), so this modeling choice is kept in Backbone. This choice leads to suboptimality but limits the computation time. This stored energy varies with the charge and discharge, considering the efficiency (η_u) which induces losses, expressed in Eq. (6). As the initial state of charge is empty batteries, the optimization forces the batteries to be empty at the end of the day, as otherwise it would represent a loss. The curtailment of VRE, which can also be considered a source of flexibility, is also modeled but without an additional cost penalty, as it is already an energy loss for the system.

$$0 \leq p_{n,u,t}^{ch}, p_{n,u,t}^{disc} \leq p_{n,u}^{cap0} + p_{n,u}^{cap} \quad \forall n \in N, u \in U^{sto}, t \in T \quad (4)$$

$$0 \leq e_{n,u,t} \leq E_{n,u}^{cap0} + p_{n,u}^{cap} \times 4 \times \Delta t \quad \forall n \in N, u \in U^{sto}, t \in T \quad (5)$$

$$e_{n,u,t} - e_{n,u,t-1} = \Delta t \times (p_{n,u,t}^{ch} \times \eta_u - p_{n,u,t}^{disc}) \quad \forall n \in N, u \in U^{sto}, t \in T \quad (6)$$

In addition to storage, three flexibility types are considered: EV, electrolyzers (EZ), and industrial processes (other than electrolysis). Electrolysis is separated from the industrial load because it uses only one process (electrolysis), while typical industries manage a set of processes simultaneously, which is more complex for load-shifting. Note that domestic water heating is also a flexibility lever, but is not a variable of the optimization problem (parameter $p_{n,t}^{dwh0}$), because in France, electric water heating is already mature and already occurs off-peak hours, i.e., during low-consumption hours. Therefore, $p_{n,t}^{dwh0}$ is already well adapted to the power production, so using it as a parameter instead of a variable saves computation time. These flexibilities of demand are part of demand-side management (DSM) mechanisms. The model of these DSM only allows load-shifting within a day. Therefore, long-term (between summer and winter) and very short-term (lower than one hour) flexibilities are not considered.

In Eq. (7), the load ($p_{n,t}^{load}$) is decomposed into EV ($p_{n,t}^{ev0}$), electrolysis ($p_{n,t}^{h20}$), industrial ($p_{n,t}^{ind0}$), water heating ($p_{n,t}^{dwh0}$), as well as the remaining loads ($p_{n,t}^{load_remain}$) regrouping the other sectors (e.g., residential appliances) for which demand modulation is not modeled. Variables are also introduced to account for the increase or decrease of the initial loads at each timestep (increase: $p_{n,t}^{ev+}$ for EV, $p_{n,t}^{h2+}$ for electrolysis, $p_{n,t}^{ind+}$ for industrial load, and decrease: $p_{n,t}^{ev-}$, $p_{n,t}^{h2-}$, $p_{n,t}^{ind-}$). EV load is only in distribution grids, electrolysis is in the transmission grid, and flexible industrial load is located on both grids.

Additional constraints are required to ensure daily energy conservation with the initial demand (Sousa et al., 2025), as in Eq. (8). Similar equations exist for EV and industrial load. The timesteps within the same representative day are gathered in the same subset ($tday \subset T$). This load shifting provides flexibility to the system by reducing the dimensioning peak load for the power system.

$$\sum_{t \in tday(t)} p_{n^{hv},t}^{h2+} = \sum_{t \in tday(t)} p_{n^{hv},t}^{h2-} \quad \forall n^{hv} \in N^{hv} \quad (8)$$

The use of water electrolysis as a source of flexibility can induce a

productivity loss for hydrogen producers as the electrolyzers cannot always run at nominal power ($P_{n^{hv}}^{cap,h20}$). The base electrolysis load is assumed constant at nominal power. These producers need then to invest in new electrolyzer capacities ($P_{n^{hv}}^{cap,h2}$) to have enough production capacity to use load-shifting (9). Therefore, without further investments, the only possibility to respect Eq. (8) is to provide no demand modulation and keep the base electrolysis load.

$$0 \leq P_{n^{hv},t}^{h20} + P_{n^{hv},t}^{h2+} - P_{n^{hv},t}^{h2-} \leq P_{n^{hv}}^{cap,h20} + P_{n^{hv}}^{cap,h2} \forall n^{hv} \in N^{hv}, t \in T \quad (9)$$

As for electrolysis, EVs cannot charge faster than the installed charger capacity ($P_{n^{mv}}^{cap,ev0}$), except if a new charger capacity is added ($P_{n^{mv}}^{cap,ev}$). However, contrary to electrolysis, the base EV load is not constant throughout the day, providing flexibility even without further investments. EVs face another constraint: their inability to be continuously connected to the grid because their primary usage is mobility. This is represented in Eq. (10) with the introduction of the share of EV connected to the grid at each timestep ($\lambda_{n^{mv},t}$). This parameter is built with behavioral analysis from (RTE, 2022) and (Gonzalez Venegas et al., 2021). MV nodes feed several houses and EVs simultaneously, so EVs are represented as a group of loads and not as single vehicles. Hence, the share of EVs connected to the grid is not represented with a binary parameter for occupancy (Gonzalez Venegas et al., 2021).

$$0 \leq P_{n^{mv},t}^{ev0} + P_{n^{mv},t}^{ev+} - P_{n^{mv},t}^{ev2-} \leq (P_{n^{mv}}^{cap,ev0} + P_{n^{mv}}^{cap,ev}) \times \lambda_{n^{mv},t} \forall n^{mv} \in N^{mv}, t \in T \quad (10)$$

As several processes are managed simultaneously, the industrial load modulation can be made without further investment, and without a significant negative economic impact (e.g., (Uemaa and Kilter,)). The only limit it faces is the number of industrial processes which can be modulated in time ($P_n^{cap,ind0}$), as expressed in Eq. (11).

$$0 \leq P_{n,t}^{ind0} + P_{n,t}^{ind+} - P_{n,t}^{ind-} \leq P_n^{cap,ind0} \quad \forall n \in N, t \in T \quad (11)$$

The modeling of the load-shifting impacts the objective of Eq. (1) via the demand flexibility cost (p^{flex}). This variable is detailed in Eq. (12) to consider the cost of new electrolyzers ($\pi^{cap,h2}$) and the cost of using load-shifting, which is similar to the formulation in (Yang et al., 2023). Operational costs represent the cost of the required communication and aggregation (π^{flex}) for flexibility. Costs to motivate participation in demand modulation are not considered in this equation but are discussed in the result section. Note that, as this work is based on a centralized optimization, it is assumed that every user behaves optimally. Therefore, market incentives to help users behave as the system needs (e.g., dynamic pricing) are overlooked.

$$p^{flex} = \underbrace{\sum_{n \in N} P_n^{cap,h2} \times \pi^{cap,h2}}_{\text{cost of installed electrolyzers}} + \underbrace{\sum_{n \in N} \sum_{t \in T} (P_{n,t}^{h2-} + P_{n,t}^{ev-} + P_{n,t}^{ind-}) \times \pi^{flex} \times \Delta t}_{\text{operating cost of flexibility}} \quad (12)$$

3. Scenario definition

Considering transmission and distribution grids to determine decarbonization pathway strategies allows for discriminating the relevance of policy and systemic choices regarding the evolution of the energy sector. This research focuses on three important drivers of evolution: the power consumption patterns, the distribution of VRE, and the types of flexibility modeled, as summarized in Table 1.

The increase in electricity consumption with the energy transition is a major challenge for the power system, related to mass electrification. The level of power consumption in 2050 will impact the upgrade of the

power system. To illustrate this, three scenarios of consumption are considered for France. They are based on the main consumption levels imagined for studies at European (ENTSO-E, 2025) and French scales, considering only the transmission grid (ADEME, 2021), (RTE, 2022). The first scenario studied (S5), with high consumption, corresponds to the 1.5°C scenario from (Keramidas et al., 2023), reaching around 750 TWh of internal electricity consumption in 2050 in France, close to the “réindustrialisation profonde” scenario from (RTE, 2022) and ENTSO-E scenarios (ENTSO-E, 2025). The two other consumption scenarios considered are kept close to the “reference/S3” and “sobriété/S2” scenarios from (RTE, 2022)/(ADEME, 2021) to build respectively medium (650 TWh in 2050, S3) and low consumption (550 TWh in 2050, S1) scenarios for this study. Each scenario targets net-zero carbon emissions in 2050. The differences in power consumption between the scenarios come from systemic (societal) choices. Indeed, the high consumption scenario integrates an increase in industrial production in France, while in the low consumption scenario, the citizens choose a less energy-consuming way of life (e.g., low-impact mobility, like bikes).

Three levels of VRE distribution are tested in this article. The first is distributed with all VRE connected to the distribution grid (S4), which is close to the most distributed scenario from (ENEDIS, 2021). Based on the same reference, the most centralized scenario with around one-third of VRE connected to the transmission grid is studied (S3), which is also the percentage found in (Eurelectric, 2024). Finally, a mostly centralized scenario is considered with two-thirds of VRE connected at the transmission level (S2). The VRE distribution is closely linked with the installed VRE capacity, varying for each scenario and displayed in the results section. To summarize, the first five scenarios (S1-S5) study the impact of the electricity demand and the share of VRE in distribution grids, with the following levels:

- Low demand: 550 TWh, medium demand: 650 TWh, high demand: 750 TWh
- Low share of VRE in MV: 33 %, medium share of VRE in MV: 66 %, high share of VRE in MV: 100 %

In the previously defined scenarios, the flexibility was provided by BESS and PSH. Five new scenarios are defined (S6-S10) with additional flexibility levers, based on load-shifting. However, it significantly increases the complexity of the optimization problem, leading to long computation times (e.g., 100 h for S10). Therefore, the analysis of the flexibility effects for each type is processed only for the central scenario (medium demand level and medium distribution of VRE plants (cf. Table 1)). In the scenarios with EVs providing demand modulation, two levels are tested, with 25 % or 50 % of EVs participating in smart charging in 2050 (the total number of EVs is determined by POLES). It means that, respectively, 75 % and 50 % of EVs have a typical load profile while the remaining share is fully controllable. This corresponds to available flexibility power close to levels envisioned in (ADEME, 2021; RTE, 2022). Industrial load-shifting is split differently for scenarios S9 and S10. In S9, the industrial DSM is provided only by industries in HV grids, while in S10, industries from both transmission and distribution grids can provide demand modulation. Note that in both cases the quantity of flexibility is the same ($P_{n^{hv}}^{cap,ind0}$), this quantity is limited by the estimated maximal capacity from POLES, which is close to other estimations for France (RTE, 2022). The scenarios study flexibility of the demand by progressively adding novel sources, ranked by growing disturbance for the user. Electrolysis requires external investments but does not impact hydrogen production, EVs require users to plug their vehicle every time it is not moving, and industrial load management demands that the industries adapt their processes to the flexibility requirements. Note that the share of users participating to

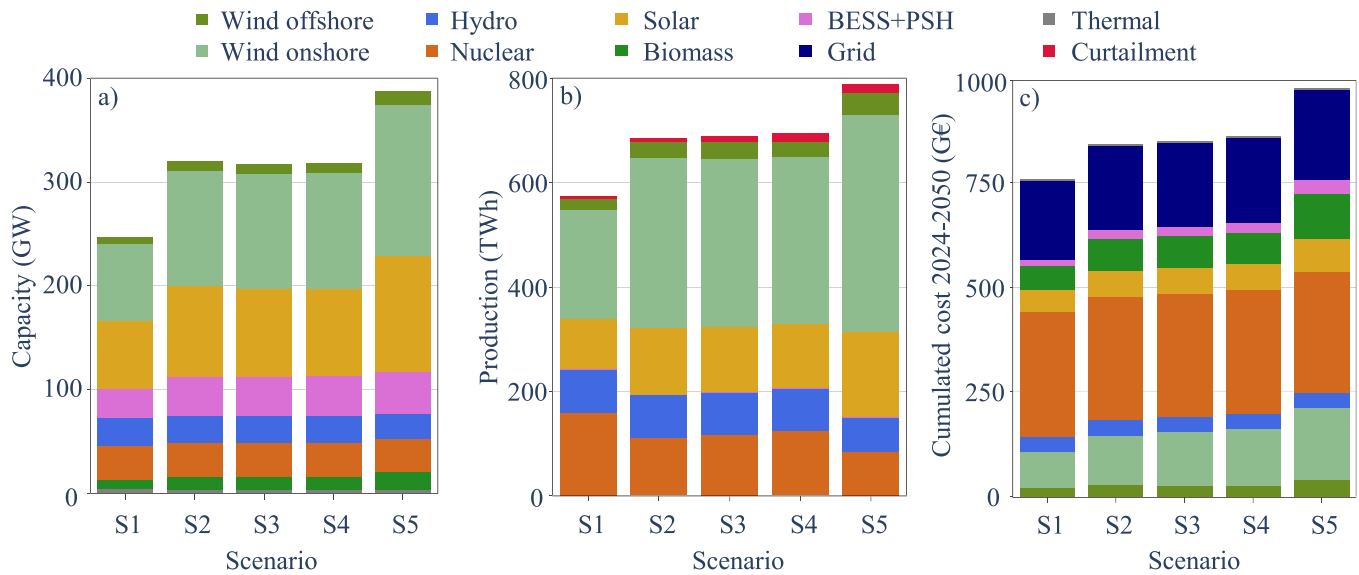


Fig. 2. Impacts of the demand level and distribution of VREs on: a) capacities in 2050, b) production in 2050, c) costs.

demand modulation increases linearly each year to reach the maximum share in 2050 (values displayed in Table 1).

4. Results

4.1. Impacts of demand levels and location of renewables

In the first set of simulations, all scenarios (S1-S5) are run without DSM. The focus is on the impacts of varying the power demand and the location of VRE. Results are analyzed at the end of the prospective period in 2050, in terms of installed capacity for generation and storage (in GW), energy production (in TWh), and the cumulated cost (in G€), displayed in Fig. 2. Overall, load demand impacts significantly more results than VRE locations. The installed capacity (Fig. 2a) is sensitive to the demand level, while the location of VRE shows little influence ($\pm 2\%$ capacity variation between S2 and S4). As the scenarios assume the same amount of nuclear installed in 2050, the capacity difference mainly comes from the VRE, with almost half of VRE capacity required in S1 compared to S5. There is still an increase of 55% for the installed

battery and 75% for biomass generators between S1 and S5. This is linked with the difference in VRE, as more VRE incurs more requirements in storage and peak power plants to handle variability. Note that the capacity mix provided by POLES is mainly driven by the price evolution of the different technologies, which is based on a global energy market.

The higher VRE capacity in S5 also impacts the energy production (Fig. 2b), which is 78% from solar and wind, whereas it is only 56% in S1. This share of VRE in production directly impacts the nuclear production, which is almost halved between S1 and S5, while the same capacity is installed. Indeed, this nuclear capacity is necessary to meet the peak during low VRE production. Therefore, nuclear plants that require high investment costs are not run optimally in S5, which could make them unprofitable. Curtailment (i.e., wasted renewable production) also varies between scenarios (multiplied fivefold between S1 and S5), but it still represents a small percentage of VRE production (less than 3%). More interestingly, the curtailments double when more VREs are installed in distribution grids (between S2 and S4), which could discourage the installation of distributed VRE. Also, backup generators,

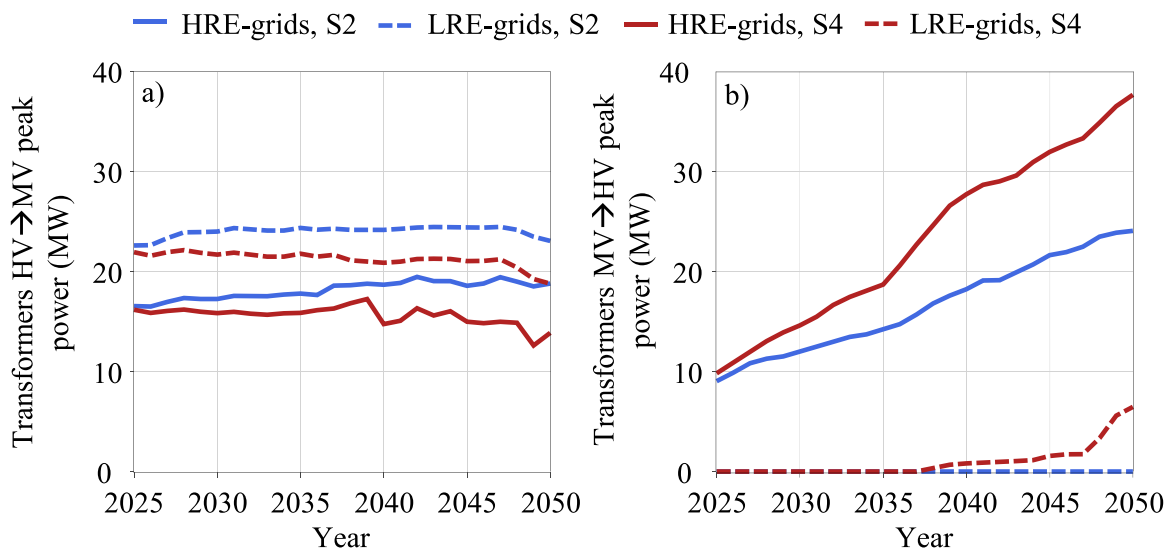


Fig. 3. Transformer peak power for different levels of VRE distribution for a) HV to MV, and b) MV to HV flows. HRE: rural MV distribution grid with a high share of renewable sources. LRE: rural MV distribution grid with a low share of renewable sources.

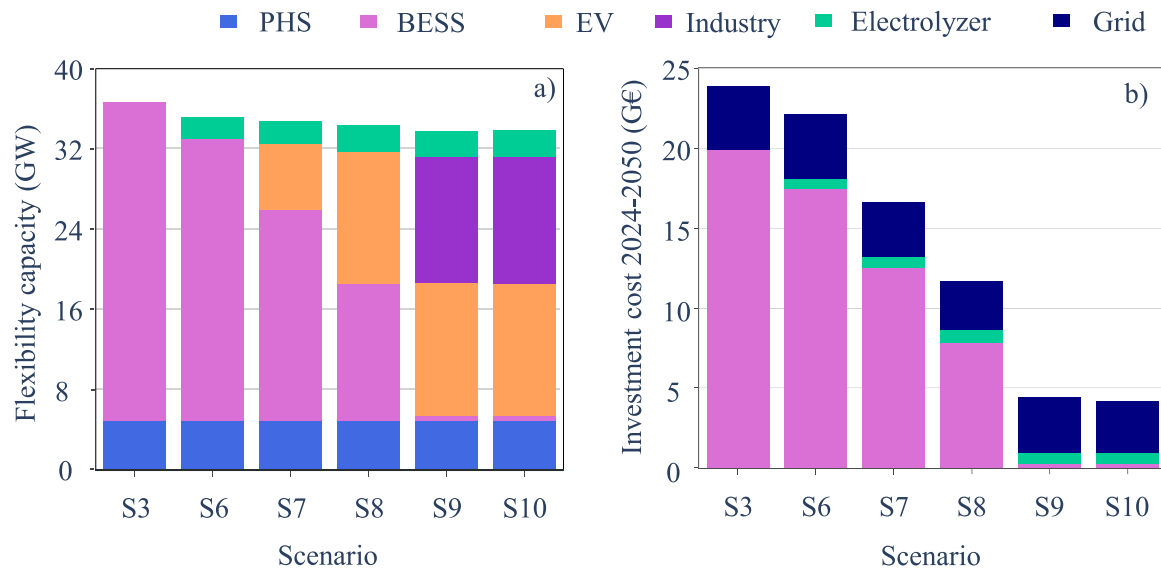


Fig. 4. Impacts of the considered flexibilities on: a) capacity in 2050, b) investment cost.

such as biomass and thermal, are not used in 2050. Their capacity has been built for needs calculated between 2035 and 2045. This underlines the interest in looking at long-term scenarios as pathways (years between today and 2050 are modeled) and not as snapshots (i.e., only 2050 is modeled).

The difference between S2 and S4, i.e., the impact of VRE location, also incurs small changes in cost ($\pm 2\%$) (Fig. 2c). This is mainly driven by the lower cost per MW of large-scale centralized power plants and by the grid investments (more details in the next paragraph). Similarly to the capacity and production results, the difference between high and low electricity demand scenarios (S5 and S1) is larger ($+32\%$), but this increase corresponds with the difference in energy provided ($+26\%$ for the 2024–2050 period, $+37\%$ in 2050). To propose a more complete grid decarbonization cost, in this figure only, grid costs contain renewals of cables (not subject to optimization) in addition to reinforcement costs described in Section 2.

To summarize, the demand level is the main driver for the sizing of the future electricity system. The low demand scenario (S1), with 25% less energy provided compared to the high demand scenario (S5), enables dividing by two the investments in VRE and storage, while dividing by three the curtailment and multiplying by two the load factor of nuclear. These results highlight the large benefits of limiting the electricity demand increase.

Grids represent around one quarter of the cumulated cost in Fig. 2. It is then interesting to understand what causes grid investment, especially relying on the capacity of the model to represent different types of distribution grids. Fig. 3 illustrates the power exchanges at the HV/MV transformer level, i.e., at the interface between transmission and distribution grids for different types of distribution grids. Those results could not be produced without the granularity of the simulation tool (i.e., representation of distribution grids, long-term and short-term simulation coupling). Results show noticeable differences depending on the amount of VRE installed in medium voltage grids (i.e., scenarios S2 and S4). This explains part of the cumulated cost difference between scenarios shown in Fig. 2c, as scenario S4 induces more grid constraints than S2. In the scenario with a lower VRE share in MV grids (S2), the power flows from HV to MV grids are higher ($+20\%$) to compensate for the deficit of local production during peak load periods (also increases with years). The type of rural MV distribution grids (with a high or low share of renewable sources, HRE and LRE, respectively) amplifies this behavior. Therefore, HRE-grids, in the highly distributed VRE scenario (S4), see their transformer MV to HV peak power exceed by far (almost threefold in 2050) the HV to MV peak power. Transformer investments

in 2050 are caused by local production, which was not the case in 2025. This explains the higher curtailments in S4, as shown in Fig. 2b. However, in the opposite case, LRE-grids in the low-distributed VRE scenario (S2) get transformers without production constraints but rather consumption-related ones (HV to MV flows). Indeed, in this case, a larger share of the demand is supplied by the centralized production, as the amount of VREs in distribution grids is not sufficient to supply the local needs. Finally, the future grid sizing depends on the location of future VRE installations. Both low and high VRE distribution scenarios present disadvantages, with some types of grid requiring significant investments. Constraints could be reduced by having a better repartition of VRE in distribution grids. Similar trends have been obtained with urban grids (not displayed here).

4.1.1. Impact of flexibility technologies

The second set of simulations focuses on flexibility technologies including DSM. Fig. 4 compares the investigated scenarios as a function of flexibility capacity and investments. Note that the demand level and VRE location ratio are the same for all scenarios. This explains the moderate variations ($\pm 8\%$) of the total capacity. Indeed, the batteries are replaced by load-shifting from the initial scenario S3. The investments required for flexibility show that adding novel DSM sources reduces investments, notably in batteries, with a reduction of 98% of the battery needs in S10. However, as this DSM causes a disturbance for consumers, they could ask a financial compensation, limiting the cost advantage of high DSM scenarios. For example, in S10, having 28 GW of demand modulation enables a saving of 20 G€. Therefore, if DSM is remunerated less than 70 €/W during this period, it is more cost-effective than batteries. Consumers who do not provide flexibility could be taxed to help finance demand modulation providers. The load-shifting of EVs does not require further investment in charging stations, as the existing ones are sufficient. It is also worth noticing that, to some extent, investing in a surplus of electrolyzers can be more financially interesting than batteries for the same service.

The repartition between regions of the solar capacity leads to higher PV (photovoltaic solar) penetration in the south of France, where the solar resource is higher, as displayed in Fig. 5a. The flexibility installed in S3 (Fig. 5b), mainly batteries (c.f. Fig. 4), tends to follow the same regional repartition as PV, to limit the grid constraints at noon. Note that the Paris region is an exception in this tendency, with higher flexibility installed than the other regions, but with low PV capacity. This exception is due to the high population density in the region, where electrification is massive and stressful for the grid. Fig. 5c shows the regional

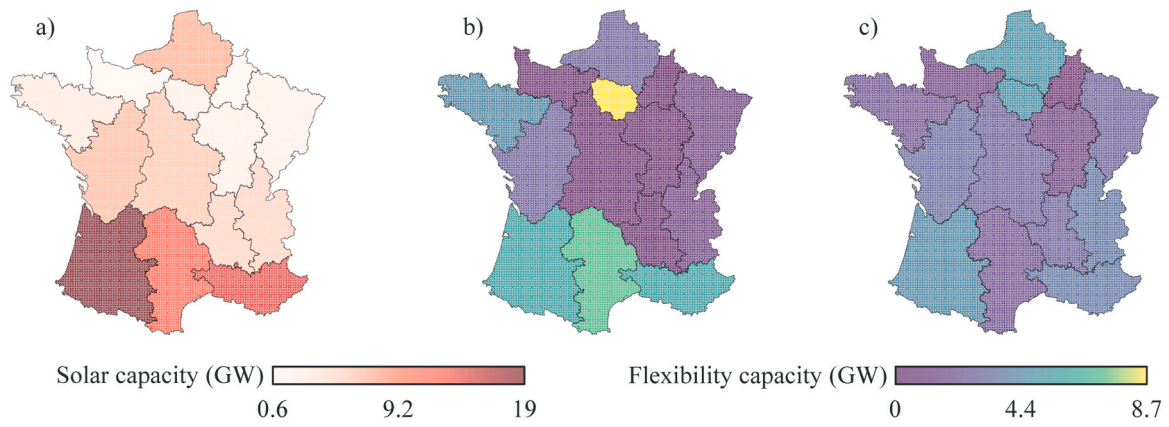


Fig. 5. Regional repartition of the capacity in 2050 for: a) solar in S3 (close to S10), b) flexibility in S3, c) flexibility in S10.

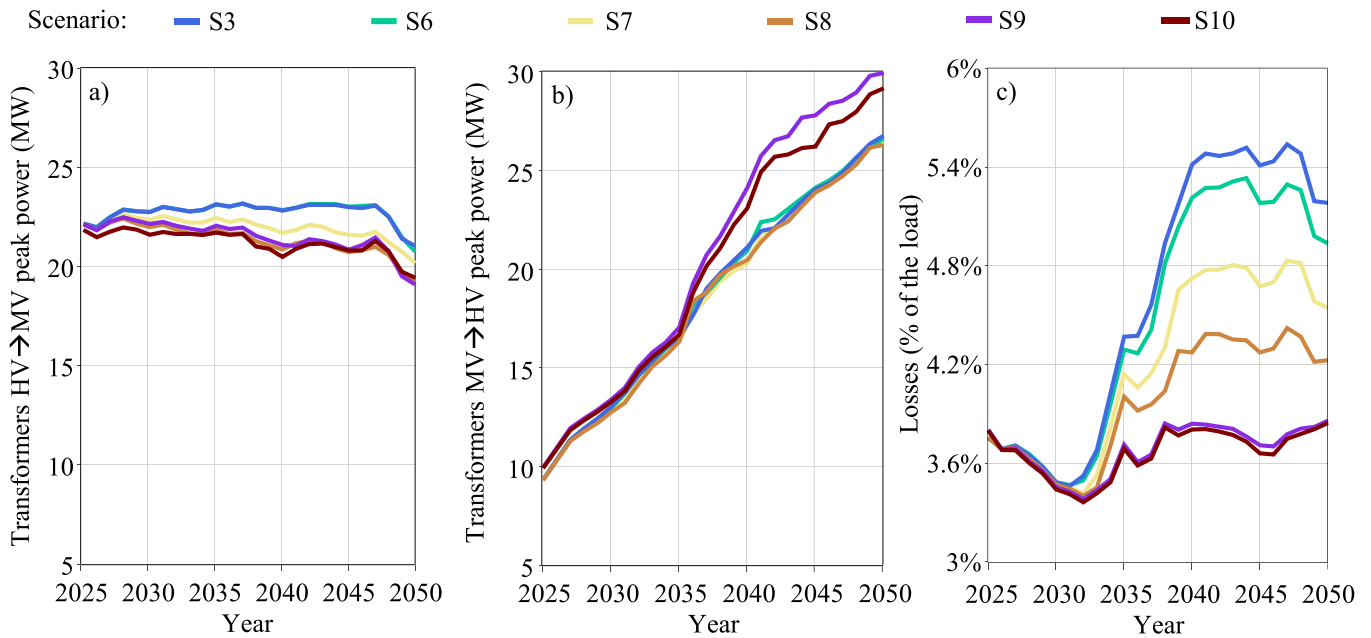


Fig. 6. Impact of flexibility options on: a) the transformer peak power for LRE-grids, b) the transformer peak power for HRE-grids, c) the losses of the whole power system.

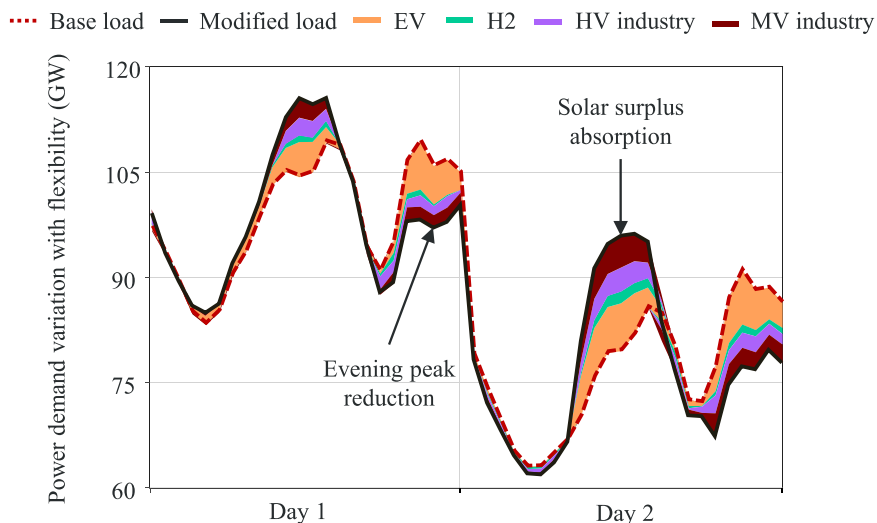


Fig. 7. Usage of the various flexibilities in S10 for two days in 2050.

repartition of flexibility for S10, in which flexibility is mainly provided by the demand. Therefore, the flexibility repartition is more balanced, as proportional to the demand. Note that the only battery investment in S10 occurs in the southwest region, where the installed PV is the highest.

The impacts on the grid of the flexibility scenarios are shown at the transformer level in Fig. 6a and b. For LRE grids, the strain on the transformers decreases with the addition of EV load-shifting. Indeed, this enables the reduction of the peak power demand on the distribution side. Peak power is an indirect image of the reinforcement requirements of the transformer, triggered each time dimensioning thresholds are crossed. For the HRE-grids (Fig. 6b), the effect of EV and electrolysis load-shifting is negligible, but the industrial one (S9 and S10) shows a negative impact, with higher peak power and thus higher investments (+ 15 %). This result is explained by the quantity of flexibility available on the distribution side in high PV regions for the scenarios with industrial DSM. Indeed, lower flexibility is installed in high PV regions in S10 (c.f. Fig. 5), thus, the MV to HV power exports in HRE-grids remain high in these regions. Having more flexibility in these high PV regions in S3 limits the PV production that flows in the transformers. Remember that contrary to LRE-grids, which are more impacted by the demand, HRE-grids' peak power is determined by the VRE production (c.f. Fig. 3). The regional repartition of flexibility then has a significant influence on the power grid, and an unbalanced DSM repartition on the territory could reduce these grid constraints.

The flexibilities have also an impact on the whole power system, with a strong influence on losses (Fig. 6c). In every scenario, the line losses are higher than today because the uneven distribution of VRE induces MV to HV power flows, to export local power surplus. This increases the power flowing in resistive lines (resistance for MV lines is significantly higher than for HV lines) and thus increases the losses. However, having a high capacity of DSM (S9, S10) limits the increase of losses to few percents compared to 2025, while they increase by 35 % in S3. Indeed, using DSM instead of batteries induces having perfect efficiency storage, compared to the 80 % round-trip efficiency of batteries. The type of

demand flexibility shows limited effects on the losses, with capacity being the major driver for loss reduction.

Fig. 7 illustrates the time series profile with the load demand along two days before and after flexibility operations. A similar pattern can be observed over the two days with an increase in the load at noon to absorb the PV surplus and a decrease in the evening peak demand to avoid starting thermal production (i.e., more cost and emissions). This highlights the value of EV charging stations installed in the workplace, to allow EV charging during the daytime. The results from Fig. 7 and Fig. 4 indicate that MV industrial demand modulation shifts significantly more energy than the HV one (+70 %) for the same installed capacity. The distributed flexibility is then more useful than the centralized one, as closer to consumption and production.

5. Discussions

As discussed in Section 3, the scenarios studied in this article derive from scenarios edited by national agencies. The installed capacity for S1, S3, and S5 is compared with some other institutional scenarios in Fig. 8. Scenarios differ in modeling assumptions. Thus, even the institutional scenarios, which have similar electricity demands by 2050 (around 450, 550, and 650 TWh), propose different energy mixes. Some capacities, such as nuclear, are mainly dependent on the policymaker's choices (input of scenarios), whereas the VRE capacity difference between scenarios depends on hypotheses such as technology prices. Overall, the investigated scenarios do not present a significant deviation from the literature. The conclusions of this paper could thus be extended to institutional scenarios used by policymakers.

Only technical constraints related to power system management have been discussed so far. However, they are not the only constraints for the evolution of power systems. As a discussion, selected resource depletion is evaluated for some prospective scenarios as a complementary evaluation criterion to costs and greenhouse gas emissions (another category of environmental impact indirectly considered in all scenarios).

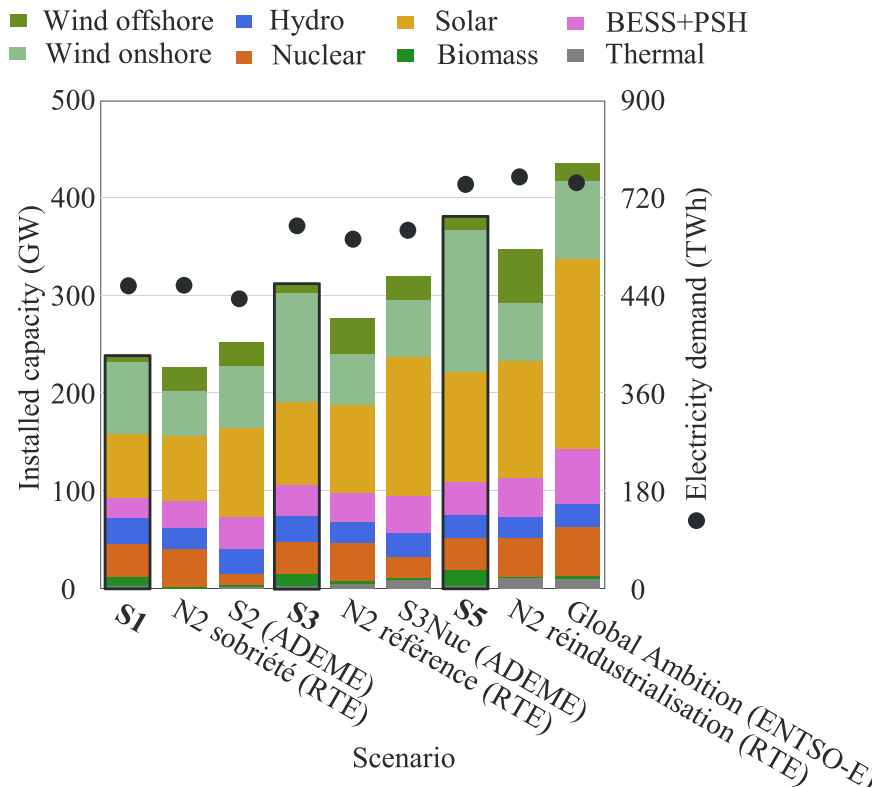


Fig. 8. Comparison of the installed capacity and electricity demand in 2050 for the main scenarios from the literature.

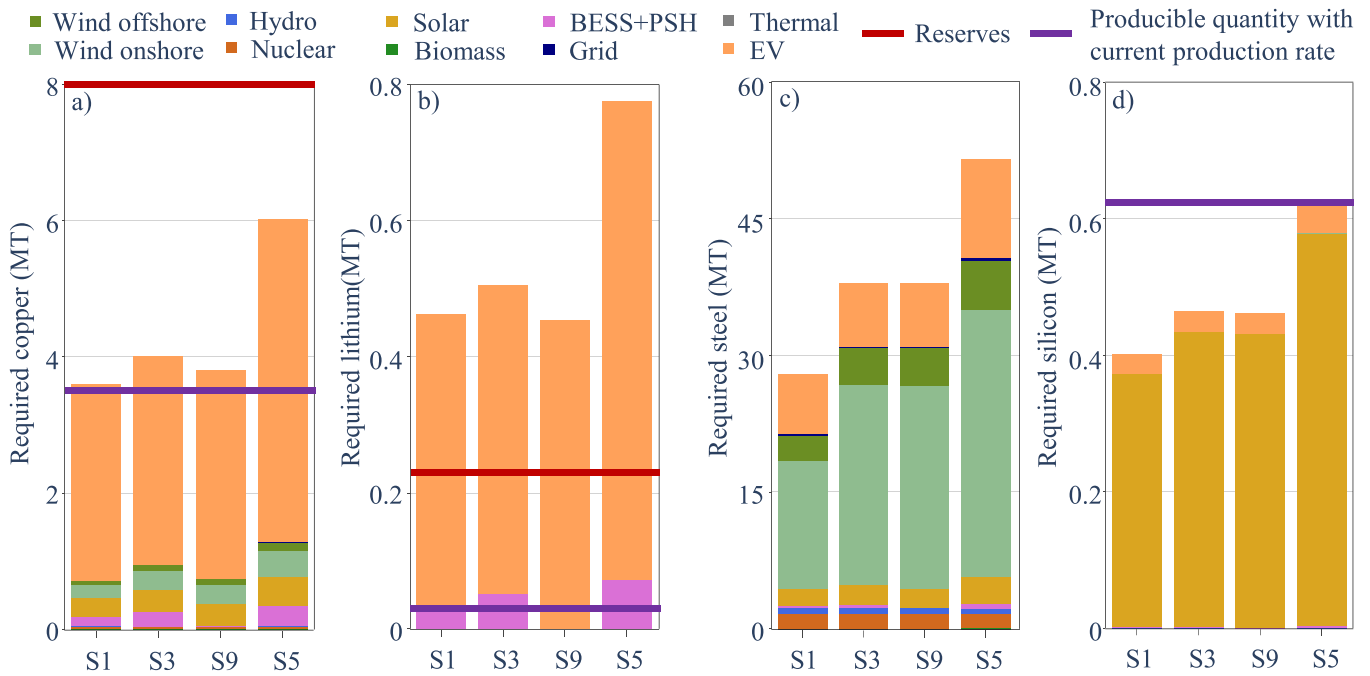


Fig. 9. Material requirements for: a) copper, b) lithium, c) steel, d) silicon.

To that end, the requirements for copper, lithium, steel, and silicon have been computed and displayed in Fig. 9. Note that this is an a posteriori analysis, meaning that these results do not impact the model. To have a more comprehensive view of the impacts of electrification, the manufacture of EVs has been taken into account in resource depletion, and even represents the majority of the demand for copper and lithium. Their tremendous impact even exceeds the estimated reserves for France. The limitation for France has been set assuming fair distribution of the global reserves according to the population share of France in the world (inferior to one percent). This fair repartition does not represent the actual situation, but given that France has few mineral resources on its territory, the share of the global production France uses could be

reduced. The world's producible quantity with a fair distribution has also been displayed to highlight mining needs. This is particularly evident in the case of lithium, where production levels are insufficient (c.f. Fig. 9b). Developing new battery technologies with materials other than lithium would then facilitate the energy transition. These results also show the importance of considering more than one mineral. Indeed, a study not considering steel would conclude that wind farms are more likely to be manufactured than solar farms, for instance. However, with this comprehensive view, no technology is flawless, and an arbitrage needs to be found. Importantly, the mineral requirements are almost halved in the lower consumption scenarios, demonstrating the relevance of sufficiency. Policies have a key role in sufficiency as they can help

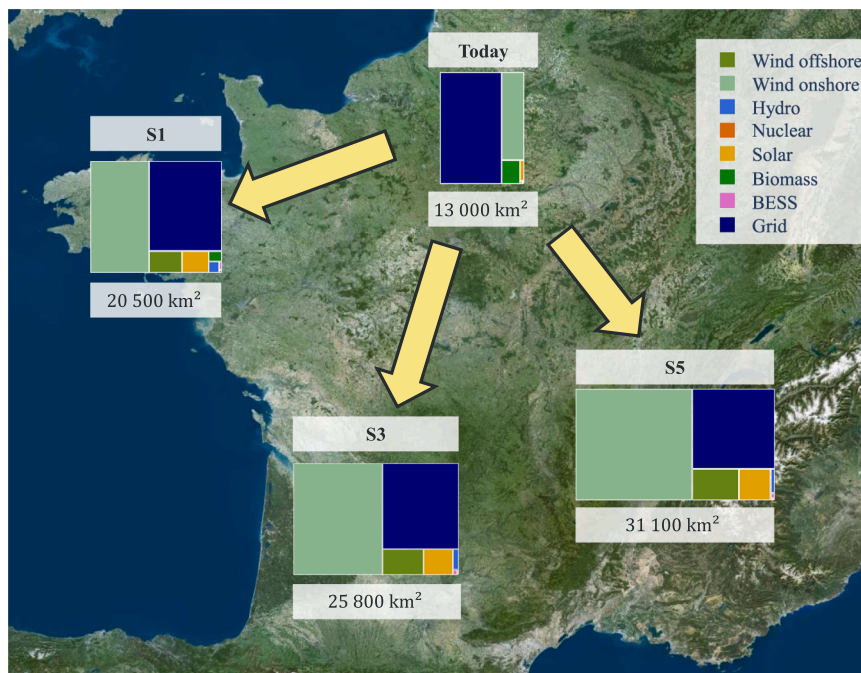


Fig. 10. Land footprint for the future French power system.

citizen change their habits (e.g., promoting cycling by building cycling roads to reduce EV demand). Note that DSM also reduces the demand for materials required for batteries, which are the most critical ones due to the large demand for EVs. Therefore, DSM should also be encouraged by policies to limit the risk of supply.

The large-scale installation of VRE requires land in addition to materials, as illustrated in Fig. 10. Note that this figure displays the real scale of the power system footprint. Today, the grid represents the majority of the land footprint of the power system (lines, substations, etc.). However, this footprint is not expected to increase much as reinforcements needed will mostly concern existing infrastructures. However, VRE, and especially wind farms will at least require as much space as the entire system of 2025, raising the question of land usage in the future. Contrary to VRE, conventional thermal generators, especially nuclear, which still produce a large share of energy in 2050 (c.f. Fig. 2), require limited land surface. Lastly, land requirements vary by a factor of 1.5 between low (S1) and high (S5) consumption scenarios, highlighting again the greater feasibility of low-demand scenarios. Land requirement is also linked with the visual disturbance that could slow the installation of wind turbines.

This work shows significant advances in energy system modeling by highlighting the strengths and weaknesses of several decarbonization pathways, but it still faces some limitations. First, there are the limitations due to the computation time, such as the number of representative days. It is impossible to properly represent one year with only 6 representative days, but increasing the number of days induces a significant increase in the computation time. For the same reason, the diversity of distribution grids that are represented is limited, and voltage and frequency issues have been overlooked. Having finer behavioral constraints for EVs and industrial flexibility would also improve the results, but would require more variables and then more computation time. This work is also limited by the tools used, especially for the representation of mineral requirements inside the model. This representation would be able to provide scenarios for which the demand does not exceed the reserves.

6. Conclusions

Distribution grids participate in reaching net-zero carbon emissions by supporting increased electrification, but are not systemically considered in long-term decarbonization pathway scenarios. This research fills this gap by analyzing several scenarios while considering both high-voltage transmission and medium-voltage distribution grids. This study proposes various scenarios for decarbonization pathways of the French energy sector by 2050, considering multiple levels of load consumption, distributed variable renewable energy (VRE), and flexibility technologies. Different types of distribution grids (rural and urban) are also considered, allowing for analysis of the power flows and losses of more realistic grids. The main findings are:

- The installed capacity and the costs are mainly influenced by the demand level.
- The choice of centralizing or distributing VRE only has a limited impact on the prospective scenarios
- Distributed flexibilities, such as electric vehicles, appear more valuable than large-scale BESS

Due to the high impact of the demand level, the scenarios with sufficiency to limit the electricity demand present fewer obstacles for the power system to reach full decarbonization. For instance, the high demand scenario requires nearly double the VRE and storage capacities compared to an energy sufficiency scenario. In that regard, policies should help citizens to have more sufficient behaviors. For example, policies can finance cycling roads to accelerate the transition toward more sustainable systems.

Even if centralizing or distributing VRE only has a limited impact at

the system scale (2 % variations in installed capacity), it affects the distribution grids. To reduce grid investments, an optimum can be found between the strain on the distribution grids to export VRE surplus and installing production close to consumption. Further research is required to test different configurations of distribution grids. Nevertheless, results tend to show that a better repartition of VRE among the distribution grids could alleviate some grid constraints. Therefore, VRE installation tariffs varying with the location could help a better repartition of VREs.

Distributed DSM is more useful to the system, but also unlocking the DSM potential of transmission grid consumers can almost make battery investment irrelevant, with a reduction of 98 % of battery needs. DSM is also more efficient than batteries in alleviating grid constraints and limiting system losses without incurring additional investments. This shows that policies should promote DSM, with financial advantages, for example. Indeed, lithium for batteries could be subject to a tension of supply, as the potential of production in France is limited.

Further research could add details on the technical feasibility of DSM from a social point of view to understand how such methods could impact the power system considering human behavior. Considering mineral reserves in the investment process would also be valuable to find scenarios that do not exceed Earth's reserves. Further research is also needed to add more countries to the study to understand how the integration of distributed renewables could impact energy exchanges between countries. Finally, only medium-term flexibility has been analyzed in this work, but short and long-term flexibility could also require batteries, which could limit the advantages of DSM.

CRedit authorship contribution statement

Silvana Mima: Supervision, Software, Methodology. **Jean-Nicolas Louis:** Supervision, Software, Project administration, Methodology. **Vincent Debusschere:** Writing – review & editing, Supervision, Project administration, Funding acquisition. **Rémy Rigo-Mariani:** Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Methodology, Conceptualization. **Corentin Jacquier:** Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization.

Declaration of Competing Interest

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

Data availability

Internal data in the long-term energy model POLES cannot be shared. All the other can be shared on request

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