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The importance of renewable gas in achieving carbon-neutrality: insights from an energy system optimization model

Behrang Shirizadeh ^{1,2*}, Philippe Quirion ¹

Abstract

To address the cost-effective role of the different energy sources and carriers, energy optimization models should ideally consider the key energy supply, carrier, conversion, and storage options in an endogenous way, with high temporal resolution, and accounting for both positive and negative CO₂ emissions. To do this, we develop a model optimizing dispatch and investment, meeting all the above-mentioned conditions, and we apply it to the French energy system for 2050 for a wide range of social cost of carbon (SCC) values (0 to €500/tCO₂).

Our findings show that (1) the optimal carbon-neutral energy system is highly electrified (~80% of the primary energy supply), which implies highly electrified heating and transport sectors. (2) In the presence of renewable gas, a carbon-neutral energy sector can be achieved for a robust SCC of €300/tCO₂. (3) In such a system, renewables provide more than 90% of primary energy. (4) Therefore, renewables are crucial for achieving carbon-neutrality in a cost-effective way, and in the absence of renewable gas, carbon-neutrality cannot be achieved, even for an SCC of 500€/tCO₂. Finally, (5) exclusion of nuclear energy from the energy system does not induce significant extra cost or emissions.

Highlights

- We study the role of renewable gas in the future low-carbon French energy system.
- Renewable gas provides at least 20% of the primary energy.
- Renewables are the main enablers of carbon-neutrality (>90% of the primary energy).
- A high degree of electrification is required in the heat and transport sectors.

KEYWORDS: Energy systems modelling; large-scale renewable integration; sector-coupling; social cost of carbon; renewable gas; nuclear energy; variable renewables; negative emissions.

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Abbreviations

ADEME	Agence de la transition écologique (French energy transition agency)	GDP	Gross domestic product
aFRR	Automatic component of frequency restoration reserves	GHG	Greenhouse gas
BEV	Battery electric vehicle	HP	Heat pump
CAPEX	Capital expenditure (overnight cost)	ICE	Internal combustion engine
CCFN	Chambre de commerce Franco-Norvégien (Franco-Norwegian Chamber of Commerce)	IDC	Interest during construction
CCGT	Combined cycle gas turbine	IPCC	Intergovernmental Panel on Climate Change
CCS	Carbon capture and storage	JRC	Joint Research Centre
cf	Capacity factor	LP	Linear programming
COP	Coefficient of performance	lt	Lifetime
DR	Discount rate	mFRR	Manual component of frequency restoration reserves
EOLES	Energy optimization for low emission systems	NGO	Non-governmental organization
EOLES_mv	Energy optimization for low emission systems, multi-vector	OCGT	Open cycle gas turbine
EPR	European pressurized water reactor	O&M	Operation and maintenance costs
EV	Electric vehicle	PV	Photovoltaics
FCH JU	Fuel cells and hydrogen joint undertaking	RTE	Réseau de transport d'électricité (French electricity transmission network operator)
FCR	Frequency containment reserves	SCC	Social cost of carbon
FRR	Frequency restoration reserves	SNBC	Stratégie nationale bas-carbone (French national low-carbon strategy)

1. Introduction

In order to meet the 1.5°C global warming objective, the European commission's 'European Climate Law' proposal sets the target of achieving climate neutrality by 2050 [1]. Similarly, several European states have set ambitious greenhouse gas (GHG) emission reduction targets; for instance, the official target in the French 'energy-climate law' is to reach net zero GHG emissions by 2050 [2]. ***Global energy consumption in 2019 was 418EJ (116.11PWh), of which 40.4% is accounted for by oil, 16.4% by gas, 9.5% by coal, 10.4% by biofuels and waste and 19.7% by electricity¹. Focusing on French energy consumption, in 2020 France consumed 1,562TWh of energy². The main energy carriers for the French energy sector were oil and refined petroleum products (41.6%), electricity (25%) and natural gas (20%). Although French electricity has a very low carbon footprint (34gCO_{2eq}/kWh_e in 2021³), electricity accounts for only one quarter of French final energy consumption and achieving carbon-neutrality requires decarbonization of the whole energy sector, not only of the electricity supply.***

Energy scenarios aiming at carbon-neutrality by 2050 vary with respect to the role of different energy carriers, particularly gas and electricity. For instance, the French Environment and Energy Management Agency (ADEME)'s 'Energy-Climate Scenario 2035-2050' and the French Ministry of Ecological Transition and Solidarity's 'National Low-Carbon Strategy', feature relatively electrified heating and transport sectors in France with up to 60% of the primary energy supply being electrified by 2050 [3], [4]. However, another scenario for France, published by the NGO négaWatt, suggests only 35% of electrification by 2050 for the primary energy supply, with the transport sector dominated by gas-fuelled internal combustion engines [5].

These national scenarios are based on top-down allocation of energy sources and carriers and do not result from explicit optimization. Considering the entire energy system as an integrated whole and optimizing it on a national scale is complicated and highly demanding in computational terms. However, ideally, a rigorous energy policy that fully considers the relative role of the different energy sources, carriers and storage options should be based on optimal allocation of those options. This optimization should include endogenous choice of energy carriers and low-carbon options (renewable electricity, biogas, carbon capture and storage and nuclear power) since these choices are interdependent. For instance, considering power-to-gas as a long-term storage option in the context of the electricity sector alone requires highly inefficient gas-to-power conversion technologies [6]. To avoid overestimation of storage needs, studies should focus on the entire energy system, not on a single sector [7]. Therefore, the endogenous technology choice should include a multi-sectorial approach to enable sector-coupling. Sector-coupling enables optimal allocation of different energy sources, carriers and storage options to satisfy the main end-use demands by allowing an endogenous choice of energy carrier and conversion options for different end-uses [8].

Correct dimensioning of short-term and long-term storage options requires high temporal resolution. A coarser-than-hourly temporal resolution lowers the model accuracy because it averages short-term variations in wind speed and solar radiation, leading to underestimation in the dimensioning of short-term storage options [9]. Similarly, long-term storage options (typically inter-seasonal storage) are among cost-optimal solutions due to annual cycles of wind, solar irradiation and temperature [10], [11], and correct dimensioning of long-term storage options requires the

¹ <https://www.iea.org/reports/key-world-energy-statistics-2021/final-consumption>

² <https://www.statistiques.developpement-durable.gouv.fr/edition-numerique/chiffres-cles-energie-2021/>

³ <https://www.rte-france.com/eco2mix/les-chiffres-cles-de-lelectricite>

modelling of a continuous, long period of time, rather than defining representative periods [12]. Therefore, modelling an optimal energy mix must consider at least one full year at an hourly resolution.

Achieving carbon-neutrality in the energy sector requires not only the penalization of positive emissions as a carbon tax, but also the promotion of negative emissions [13]. To sum up, identification of the relative role of different energy carriers requires an integrated optimization that (1) includes the main energy sectors, (2) is based on endogenous energy carrier and technology choices (simultaneous optimization of investment and operation), (3) includes the main low-carbon options, (4) has a high temporal resolution over at least a full year and (5) accounts for both positive and negative CO₂ emissions.

Most energy system optimization models only represent the electricity sector [13], [14], [15], [16], [17], etc. **Although multi-energy systems featuring sector-coupling have gained significant attention recently, as shown in the reviews by Mancarella [74] and Fodstad et al., they face “a trade-off between the level of technological detail and temporal resolution” [75].** Therefore, the existing energy system optimization studies that include sector-coupling either lack the required temporal resolution [18] or lack complete endogeneity in the interactions between energy carriers and end-use demands. They also suffer from limited representation of the main low-carbon options, especially negative emission technologies [19], [20], [21], [22], [23]. Moreover, none of these studies include internalization of both negative and positive CO₂ emissions, which is a key element in studying the potential of different mitigation options. **This gap in the literature is mentioned in the recent review by Fogstad et al. who mention the lack of analysis of “combined natural-gas and CCS value chains, together with H₂” [75].** To include all the conditions mentioned above in an optimal decision-making process aiming at carbon-neutrality, we develop the EOLES_mv (Energy

Box 1. Brief comparison of EOLES_mv model with other widely used models.

Models compared	Advantages of EOLES_mv	Disadvantages of EOLES_mv
TIMES models¹	- High temporal resolution, - Simultaneous optimization of dispatch and investment, - Inclusion of a continuous long period.	- Limited representation of the energy value chain, - Low spatial resolution, - Static modelling.
ELMOD models²	- Higher level of sector-coupling, - Representation of the whole energy sector.	- Lower spatial resolution, - Static modelling, - Limited representation of power transmission
DIETER models²	- Higher sector-coupling, - Representation of the whole energy system.	- Limited representation of heat and power sectors and their interactions.
PyPSA models³	- Higher Temporal resolution, - Higher level of sector-coupling.	- Lower spatial resolution, - Static modelling.
MESSAGE models⁴	- High temporal resolution, - Long continuous weather period taken, - Simultaneous optimization of dispatch and investment.	- Lower spatial resolution, - Static modelling, - Limited representation of the energy value chain, - Exogenous economy-energy relationship.
Balmorel⁵	- EOLES_mv has optimization, high temporal resolution for a continuous period and sector-coupling all simultaneously in one single version of model.	- Lower Spatial resolution, - Limited representation of the energy value chain, - Static modelling.

Optimization for Low Emission Systems, multi-vector) model, which meets all the conditions highlighted above. EOLES_mv simultaneously optimizes dispatch (providing an hourly supply-

demand balance) and investment in production, storage, network and energy conversion capacities, in order to minimize the total cost of energy systems. **Box 1 compares EOLES_mv with some of the recent and state-of-the-art energy and electricity system models^{1,2,3,4,5}, representing at least one example of each type of model in the literature.**

Applying the EOLES_mv model to the French context, we study, for different social cost of carbon⁶ scenarios (from 0 to €500/tCO₂), the relative role of the main energy carriers and the importance of the key low-carbon technologies in achieving carbon-neutrality in cost-optimal ways. Finally, accounting for the main uncertainties, we propose a robust social cost of carbon to ensure that the goal of deep decarbonisation is achieved.

The remainder of this paper is organized as follows. Section 2 presents the methods: the EOLES_mv model and the input parameters. Section 3 presents the results, which are discussed in section 4. Section 5 highlights the main findings and concludes.

2. Material and methods

This section documents the EOLES_mv model and the input data used in it. Figure 1 shows the research flowchart for this study.

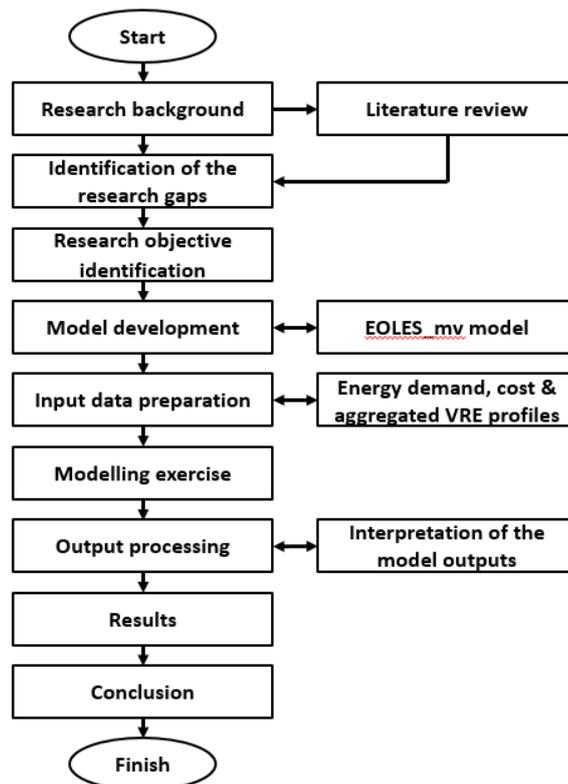


Figure 1. Research flowchart for the current study

¹ <https://iea-etsap.org/index.php/etsap-tools/model-generators/times>

² https://www.diw.de/en/diw_01.c.599753.en/models.html

³ <https://pypsa-eur-sec.readthedocs.io/en/latest/>

⁴ <https://previous.iiasa.ac.at/web/home/research/researchPrograms/Energy/MESSAGE.en.html>

⁵ <http://www.balmorel.com/index.php>

⁶ The social cost of carbon (SCC) is the monetary value that society attributes to one marginal metric ton of CO₂ emissions.

2.1. The EOLES_mv model

The EOLES family of models performs simultaneous optimization of the investment in and the operation of the energy system in order to minimize the total cost while satisfying energy demand. **Therefore, both installed capacity and the hourly energy production of each technology are optimized (under constraints).** The “mv” in EOLES_mv stands for multi-vector and this model minimizes the annualized energy generation, conversion and storage costs, including the cost of connection to the grid, as well as the cost attributed to of CO₂ emissions (the “social cost of carbon”).

The annualized cost includes the operation and maintenance costs as well as the annualized investment cost (the annuity, the value of which is presented in Tables 2-4). The annuity takes into account the discount rate, the overnight construction cost, the lifetime and the lead time of investment, as detailed below. Since we seek a long-term optimum, we focus on year 2050 and consider that it represents a steady-state. Therefore we do not model the years between now and 2050, during which the existing generation capacities will be progressively phased out.

EOLES_mv considers all the major energy-consuming sectors (residential and tertiary buildings, industry, transport and agriculture) in an integrated manner, enabling sector-coupling. The model is static **and partially greenfield**: it calculates a cost-optimal steady state, taking into account the main technical and resource availability constraints, **by keeping only the capacities that will remain in the French energy system by 2050**. In order to account for precise dispatch with correct dimensioning of storage technologies and the seasonal and intra-daily variability of demand and energy production from renewable resources, the selected optimization period is a full year with hourly time-steps.

This model considers a country as a single node using the copper-plate assumption: spatial optimization is, therefore, not considered in this model. Although including spatial optimization and therefore transmission costs can increase or decrease the overall system cost, in a previous article we showed that modelling France as a single node with a near-optimal assumption of installation of new plants in proportion to existing facilities (which is the case in this study – section 2.2.1 and Appendix B) leads to much faster calculation (240 times) than considering France as four nodes, with negligible error in installed capacity of the key technologies and the overall cost of the system [10].

The EOLES_mv model includes seven power generation technologies: floating and monopile offshore wind power, onshore wind power, photovoltaic solar power (PV), run-of-river and lake-generated hydroelectricity, nuclear power (EPR, i.e., third generation European Pressurized Water Reactors) and three gas production technologies: fossil gas, methanization from anaerobic digestion and pyro-gasification of solid biomass.

Sector-coupling is enabled by vector-change (energy conversion) technologies: open-cycle gas turbines (OCGT), combined-cycle gas turbines (CCGT) and CCGTs equipped with post-combustion carbon capture and storage (CCS) technologies are used to convert gas to electricity. Vector-change from electricity to gas is enabled by methanation (hydrogen production from electrolysis of water and use of the Sabatier reaction between the hydrogen produced and green CO₂ to produce synthetic methane) as a power-to-gas option. On top of that, hydrogen demand is satisfied by producing it from electricity using electrolyzers. Moreover, the hydrogen thus produced can be used for combustion in suitably-adapted OCGT power plants to produce electricity if it exceeds the hydrogen demand. Similarly, centralized and decentralized boilers are used to produce heat from gas, while centralized and individual heat pumps as well as resistive heat technologies are used to produce heat from electricity.

The model includes two electricity storage technologies (Li-Ion batteries and pumped hydro storage), the existing gas network as the gas storage option, salt caverns as the hydrogen storage option and two heat storage technologies (centralized and decentralized hot water tanks). Moreover, EOLES_mv allows demand for transport to be met with an endogenous choice between electric vehicles and internal combustion engine vehicles, for the three main transport categories: light vehicles, heavy vehicles¹ and buses (all trains are set to be electric since they are currently overwhelmingly electric in France). The interactions between the different energy end-use demands, supply side, storage and energy carriers are presented in Figure 2.

The EOLES_mv model is based on representative technologies chosen from groups of technologies with similar technical and economic behaviour. For instance, only two engine types are considered in the transport sector: gas-fuelled internal combustion engine (ICE) vehicles and battery electric vehicles (BEV). Other transport options include liquid-fuelled ICE vehicles and hydrogen-fuelled fuel cell electric vehicles but since they have similar economic and technical behaviour to gas-fuelled ICE vehicles and BEVs respectively, they have been excluded in order to maintain computational tractability.

The main simplification assumptions in the EOLES family of models are as follows: demand is inelastic², and the optimization is based on full information about the weather and electricity demand. This model uses only linear optimization: non-linear constraints might improve accuracy, especially when studying unit commitment, however they entail significant increase in computation time. Palmentier has shown that linear programming provides an interesting trade-off, with little impact on cost, CO₂ emissions and investment estimations, but speeds up processing by up to 1,500 times [24]. The model is written in GAMS and solved using the CPLEX solver. The GAMS scripts and the input data are available on Github.³ The model's indices, parameters, variables and equations are presented in Appendix A.

¹ In France, light and heavy transport categories are distinguished by a 3.5-ton limit, where all road transport exceeding this value is considered to be heavy.

² ***The energy demand is inelastic from the end-use demand point of view, nevertheless, the technology choice for satisfying the end-use demand for different sectors is endogenous which can lead to a change in energy consumption level depending on the energy vector and technology choice. Moreover, the transport sector has a refueling/charging flexibility via smart charging which is explained in Appendix 3 (page 36, equations A.16 and A.17). Moreover,*** the relatively low level of energy demand modelled already assumes significant energy savings. Therefore, it is more consistent with an intermediate or high social cost of carbon. This is discussed in section 4.5.

³ <https://github.com/BehrangShirizadeh/EOLES>

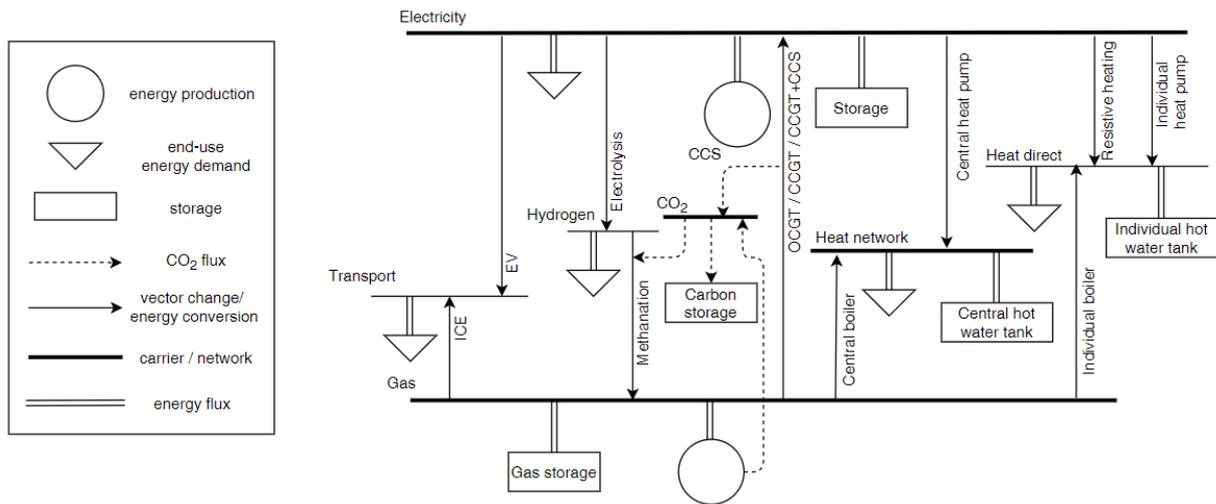


Figure 2. Schematic diagram of the EOLES_mv model; the figure on the right shows the interactions between energy supply, demand, storage and carriers by energy flux and CO₂ exchanges. The box on the left provides the key to the shapes. The two energy supply technologies are electricity and gas production, each connected to its own network.

2.2. Input parameters

2.2.1. VRE profiles

Variable renewable energy (VRE) (offshore and onshore wind and solar PV) hourly capacity factors were prepared using the renewables.ninja website¹, which provides the hourly capacity factor profiles of solar and wind power from 2000 to 2018 at the geographical scale of French counties (*départements*), following the methods elaborated by [25] and [26]. These renewables.ninja factors reconstructed from weather data provide a good approximation of observed data: Moraes et al. find a correlation of 0.98 for wind and 0.97 for solar power with the observed annual duration curves (in which the capacity factors are ranked in descending order of magnitude) provided by the French electricity transmission system operator (RTE) [27].

In a previous article, we showed that 2006 can be chosen as the representative year for the 2000-2018 period regarding variability of VRE technologies in relation to weather; thus, we use the hourly VRE and hydro-electricity profiles for the year 2006 [10]. Appendix B provides more information about the methodology used in the preparation of hourly capacity factor profiles of wind and solar power resources.

2.2.2. Energy demand

The energy demand is categorized for each end-use, i.e. electricity, heat, transport and hydrogen (for the industry sector) covering all the main energy sectors: residential and tertiary buildings, industry and construction, agriculture and transport. Unlike the existing literature, we define the end-uses and allow the model to make the optimal choice to satisfy demand in different sectors for different end-uses. As an example, the EOLES_mv model optimizes the required transport energy carrier (EV or ICE) for three of the four main transport categories (light and heavy vehicles and buses). Similarly, to satisfy hourly heat demand profiles, the choice of heat production is optimized over five energy conversion technologies from electricity or gas to heat. Therefore, the model chooses the optimal heat production mix endogenously among different central/decentralized and power-to-heat/gas-to-heat options to satisfy the exogenous hourly heat demand.

¹ <https://www.renewables.ninja/>

The annual energy requirement for each energy sector is taken from ADEME’s update of the ‘Energy-Climate Scenario’ for 2050 [3]. While different end-uses are provided in detail for the residential sector, this detail is not included for the tertiary, agriculture and industry sectors. Another future annual demand projection for France is provided by the French National Low-Carbon Strategy [2]. The sectorial demands are very similar in these two studies, but the latter provides more detail about energy end-use for the transport and tertiary sectors. Therefore, taking the same values found in [3], we use the final energy demand allocation for the tertiary sector from the second report. Transport demand is taken from ADEME’s ‘Energy Climate Scenario’ in Gp.km and Gt.km units [3] and using the occupation rate of different passenger and freight transport demands presented in [2], we calculated the annual transport demand for each transport category in vehicle-kilometres. The demand for agriculture and industry are separated by end use in négaWatt’s ‘2017-2050 scenario’ study [5]. Therefore, using the same overall energy demand in industry and agriculture provided by [3], we use the allocation of heat and electricity demand provided by négaWatt to find the end-use demand for each of these technologies. The preparation of each end-use demand profile is presented in Appendix C. Table 1 summarizes the assumed annual demand for each sector and its end-use, and the sources of these annual values and hourly profiles.

Table 1. Assumed sectorial demands for each end-use

Sector	End-use	Annual Value (Mtoe)	Source	Profiles from	
Residential	Electricity	6.2	[2], [3]	[28]	
	Heat	18.5		[18]	
Tertiary	Electricity	7.2	[2], [3]	[28]	
	Heat	7.1		[18]	
Agriculture	Electricity	1.4	[3], [5]	[28]	
	Heat	1.6			
Industry	Electricity	6.7	[3], [5]	[28]	
	Low temperature heat	6.0		Flat	
	Mid temperature heat	2.9		Flat	
	High temperature heat	3.8		Flat	
	Hydrogen	3.5	[3]	Flat	
Transport	Passengers (in Gp.km)	Light	[3]	[18]	
		Public		51	
		Train		187	Flat
	Freight (in Gt.km)	Heavy		347	[18]
		Train		127	Flat

2.2.3. Limiting capacity and energy production constraints

We use the maximal capacities of VRE technologies from ADEME’s ‘Electric System Trajectories 2020-2060’ study [29], the maximal and existing hydro-electricity capacities from [28], and the hourly run-of-river and lake-generated hydro-electricity profiles from the French national open data forum, provided by RTE (French transmission network operator). **The maximal capacities include some environmental and social constraints, not only technical limits.** By summing the hourly lake-generated hydro-electricity profiles for each month, we calculated the maximum amount of electricity that can be produced from this technology for each month. Similarly, the maximum biogas production from renewable gas¹ production technologies (methanization and pyro-gasification) are

¹ Renewable gas, also known as bio-methane, is a biogas which has an upgraded quality similar to fossil gas or methanation as a power-to-gas option (hydrogen production from water electrolysis and methanation using the Sabatier reaction between hydrogen and green CO₂) that can be injected directly into the gas network. In its biogas form, it is produced using biochemical processes from organic waste (methanization) and gasification of energy wood and biomass.

taken from the upper limits of ADEME's '100% renewable gas mix' study [30]. According to the same study, the production of biogas from methanization leads to 70% of methane and 30% of carbon dioxide, which is used as the biogenic CO₂ for the methanation process.

2.2.4. Economic parameters

Table 2 summarizes the economic parameters (and their sources) of energy supply technologies used as input data in the EOLES model. Since four energy carriers are considered (electricity, gas, hydrogen and heat), the values are either in kW_e and MWh_e (for electricity) or in kW_{th} and MWh_{th} (for gas and heat). Since we are studying the optimal state of the French energy sector for 2050, the economic parameters used are all forecasts for 2050.

Table 2. Economic parameters of energy production technologies

Technology	Overnight costs (€/kW)	Lifetime (years)	Annuity (€/kW/year)	Fixed O&M (€/kW/year)	Variable O&M (€/MWh)	Construction time (years)	Source
Offshore wind farm - floating	3,660	30	246.4	73.2	0	2	[31]
Offshore wind farm - monopile*	2,330	30	157.4	47	0	2	[31]
Onshore wind farm*	1,130	25	81.2	34.5	0	1	[31]
Solar PV*	423	25	30.7	9.2	0	0.5	[31]
Hydroelectricity – lake and reservoir	2,275	60	115.2	11.4	0	1	[31]
Hydroelectricity – run-of-river	2,970	60	150.4	14.9	0	1	[31]
Nuclear power	3,750	60	262.6	97.5	9.5**	10	[32]
Fossil gas	-	-	-	-	23.5***	-	[33]
Methanization	370****	20	31	37	50	2	[30]
Pyro-gasification	2500	20	209.5	225	32*****	2	[30]

*For offshore wind power on monopiles at 30km to 60km from the shore, for onshore wind power, turbines with medium specific capacity (0.3kW/m²) and medium hub height (100m) and for solar power, an average of the costs of utility scale, commercial scale and residential scale systems without tracking are taken into account. In this cost allocation, we consider solar power as a simple average of ground-mounted, rooftop residential and rooftop commercial technologies. For lake and reservoir hydro we take the mean value of low-cost and high-cost power plants.

**This variable cost accounts for €2.5/MWh-e of fuel cost and €7/MWh of other variable costs, excluding waste management and insurance costs.

*** The price projected for Europe in 2040 in the sustainable development scenario, standing for \$7.5/MBtu.

****The overnight cost for methanization is the investment cost of the purification plants for syngas.

*****The overnight cost only accounts for the gasification plants, while the wood used for energy is accounted for in variable costs.

Construction time is the period between the date of the first expenditure on public works and the last day of construction and tests, when the plant starts operation; local authority permit processes and preliminary business studies are, therefore, not included in this period.

It should be noted that the annuity includes the interest during construction (IDC) relating to the construction time, and the decommissioning cost for nuclear power plants. The construction time for nuclear power plants can be as little as seven years, while the three ongoing projects at Olkiluoto in Finland, Hinkley Point C in the UK and Flamanville 3 in France show much longer construction times. According to the Nuclear Energy Agency, an average construction time of 10 years is a good estimation for new nuclear power plants [34]. The same report provides a labour-during-construction profile: the annual construction expenditure has been calculated assuming expenditure

to be proportional to labour each year. Using the formula provided by [35], the interest during construction can be calculated using equation (1):

$$IDC = \sum_{j=1}^{ct} C_j [(1+r)^{t_{op}-j} - 1] \quad (1)$$

Where IDC is the interest during construction, C_j is the money spent during year j of construction, ct is the construction time and t_{op} is the year the power plant starts operating. Solving this equation leads to $IDC = \text{€}1,294/\text{kW}$. According to the same GEN IV study, decommissioning of a nuclear power plant accounts for 10% of the overnight costs. Including these interest-during-construction and decommissioning costs, the final investment cost is found to be $\text{€}5,419/\text{kW}$, which is the value used to calculate the annuity.

Table 3 shows the economic parameters of energy conversion technologies.

Table 3. Economic parameters of conversion technologies

Technology	Overnight costs (€/kW)	Lifetime (years)	Annuity (€/kW/year)	Fixed O&M (€/kW/year)	Variable O&M (€/MWh)	Construction time (years)	Conversion efficiency	Source
OCGT	550	30	35.3	16.5	0	1	0.45	[32]
OCGT hydrogen	700	30	44.9	20	0	1	0.40	[36]
CCGT	850	30	56.9	21.25	0	2	0.63	[32]
CCGT-CCS	1280	30	89.2	32	5.76*	3	0.55	[31]
Electrolysis (Power-to-H ₂)	450	25	33.1	6.75	0	2	0.8	[37]
Methanation (Power-to-CH ₄)**	450/700	25/20	89.3	59.25	5***	2	0.8/0.79	[37]
Resistive	100	20	7.86	2	0	0.5	0.9	[20]
Individual heat pump	1050	20	82.54	36.75	0	0.5	Hourly profile	[38]
Central heat pump	700	20	55.02	24.5	0	0.5	Hourly profile	[38]
Central gas boiler	63	20	4.95	0.945	0	0.5	0.9	[20]
Individual gas boiler	175	20	13.76	3.5	0	0.5	0.9	[20]

* This variable cost accounts for a 500km CO₂ transport pipeline and offshore storage costs estimated by [39].

**Methanation is the combination of hydrogen production from electrolysis and the Sabatier reaction of green CO₂ as a by-product from methanization with the hydrogen produced, therefore the economic parameters of each production are presented as electrolysis/Sabatier.

***As in [10].

The conversion efficiency is in the output energy form over the input energy form. Therefore, for Gas-to-Power technologies (OCGT, CCGT and CCGT-CCS) it is expressed in $\text{kW}_e/\text{kW}_{th}$, for Power-to-Gas technologies (electrolysis and methanation) in $\text{kW}_{th}/\text{kW}_e$, for Power-to-Heat technologies (resistive heating and electric heat pump) also in $\text{kW}_{th}/\text{kW}_e$ and for Gas-to-Heat technologies (gas heat pump and central and non-central gas boilers) in $\text{kW}_{th}/\text{kW}_{th}$. To calculate the hourly coefficient of performance (COP) of heat pumps, we used the equation communicated by [20], where the hourly COP is a function of the room temperature and the ambient temperature.

Table 4 shows the economic parameters of power storage technologies, and Table 5 shows the economic parameters for transport technologies.

Table 4. Economic parameters of storage technologies

Technology	Overnight costs (€/kW)	CAPEX (€/kWh)	Lifetime (years)	Annuity (€/kW/year)	Fixed O&M (€/kW/year)	Variable O&M (€/MWh)	Storage annuity (€/kWh/year)	Construction time (years)	Efficiency (input / output)	Source
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Pumped hydro storage (PHS)	500	5	55	25.8050	7.5	0	0.2469	4	90%/90%	[40]
Battery storage (Li-Ion)	140	100	12.5	15.2225	1.96	0	10.6340	0.5	90%/95%	[41]
ITES	0	18.38	20	-	0	0	1.4127	0.5	90%/90%	[20]
CTES	0	0.64	40	-	0	0	0.0348	1	90%/75%	[20]
Gas storage*	0	0	80	0	0	2	0	1	100%/99%	[42]
Hydrogen (salt cavern)	0	1	30	0	0	0	0.07	3	100%/98%	[43]

*The French gas network is already operational for methane injection; therefore, no network development cost is considered. However, the network usage fee of €2/MWh_{th} for the gas network is derived from the French energy regulation commission [42].

Table 5 Economic parameters for two transport engine types

Technology	Charging infrastructure (€/kW)	Reservoir (€/kWh)	Lifetime (years)	Charging annuity (€/kW/year)	Reservoir annuity (€/kWh/year)	Source
<i>Electric vehicles</i>	85.7*	100	10	11.1	12.6	[44]
<i>ICE vehicles</i>	180**	0	15	17.1	0	[18]

*We consider a charging point cost of €600 for 7kW of charging power.

**According to [18], a gas charging station which can serve 400 vehicles per day costs €300,000: assuming nearly 100kWh_{th} (384km of autonomy) of charging at each charge, we obtain this cost.

All the remaining technical, land-use related, and country-specific parametrization of the model is presented in Appendix D.

2.2.5. Choice of the discount rate

The discount rate recommended by the French government for use in public socio-economic analyses is 4.5% [45]. This discount rate is used to calculate the annuity in the objective function, using the following equation:

$$annuity_{tec} = \frac{DR \times CAPEX_{tec} \times ((DR \times ct_{tec}) + 1)}{1 - (1 + DR)^{-lt_{tec}}} \quad (2)$$

Where DR is the discount rate, ct_{tec} is the construction time, lt_{tec} is the technical lifetime and $annuity_{tec}$ is the annualized investment cost of the technology tec .

2.3. The SCC scenarios

The SCC values are based on the official ‘value for climate action’ social cost of carbon introduced by [46] for France for 2050, (between 600€/tCO₂ and 900€/tCO₂). However, the results presented are for a maximum 500€/tCO₂ of SCC, since for higher values, we have not observed any significant change in the energy mix or emissions.

3. Results

3.1. Energy mix

Figure 3 shows the primary energy production. With no SCC, about 73% of the primary energy comes from fossil gas. For an SCC of 100€/tCO₂, the proportion of fossil gas in primary energy production more than halves and for 200€/tCO₂ it is completely abandoned and replaced by increased electrification and bio-methane from methanization. Nuclear power becomes part of the energy mix for an SCC between 100 and 400€/tCO₂, but the proportion of this technology in primary energy never exceeds 8%.

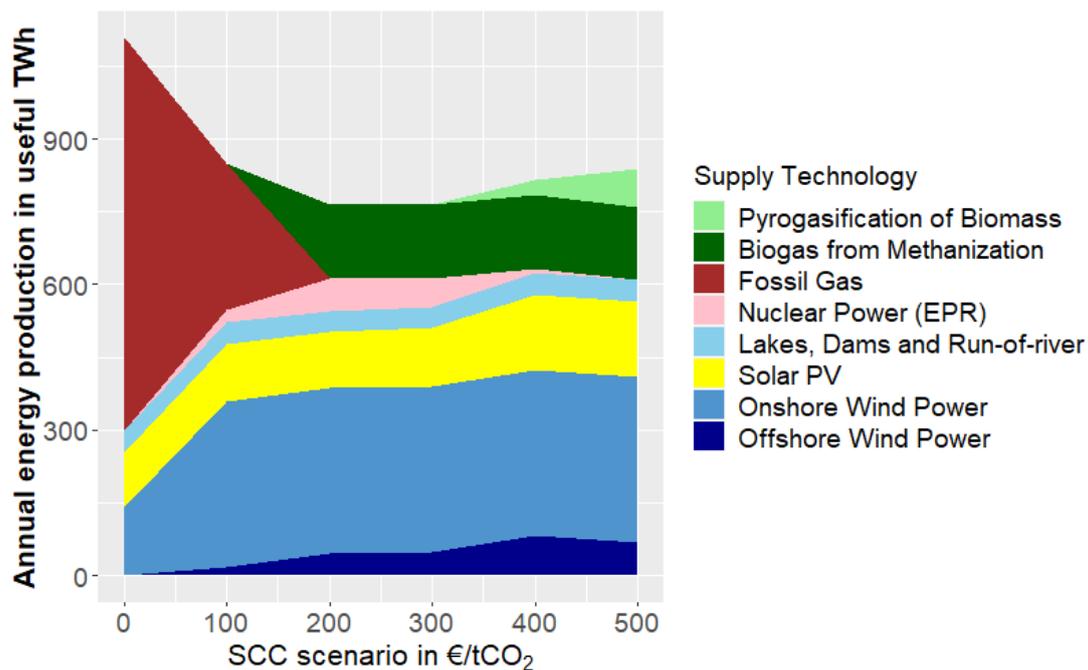


Figure 3. Primary energy production for each SCC scenario

The gas network provides 20% to 73% of primary energy production. When the SCC is high enough for fossil gas to be phased out, renewable gas from methanization provides 20% of the primary energy supply. As the SCC increases (for €400/tCO₂ and €500/tCO₂), the proportion of renewable gas increases to 27% of primary energy production. Starting from an SCC value of €200/tCO₂, methanization is fully exploited and the upper limit of annual renewable gas production from this technology (152 TWh_{th}/year) is reached. Pyro-gasification enters the optimal mix for €400/tCO₂, and it reaches its upper limit of 77 TWh_{th}/year for €500/tCO₂. Installed capacity and annual energy production by primary energy source are presented in Appendix F.

With no SCC, nearly 20% of the electricity production comes from fossil gas (Figure 4). When the SCC value increases, variable renewables and, to a lesser extent, nuclear energy replace fossil gas, and for high SCC values (more than €300/tCO₂) combined cycle gas turbines with carbon capture and storage (fuelled with renewable gas) replace nuclear energy. The proportion of electricity in the primary energy supply increases from 27% to up to 80% as the SCC increases, thanks to electrification of the heat sector, replacement of fossil gas in electricity production by nuclear power and an increased proportion of power-to-gas.

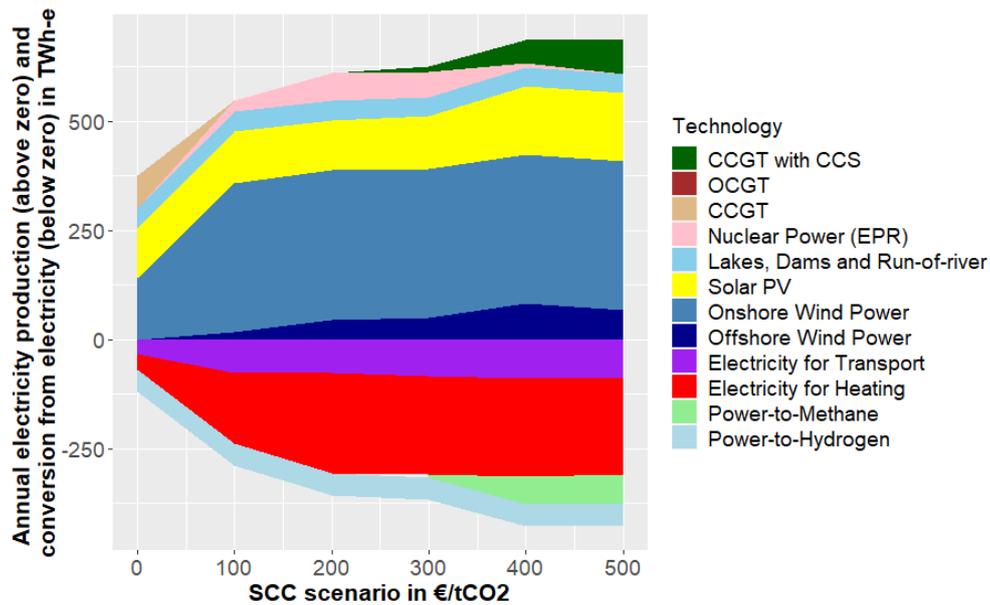


Figure 4. Electricity production (positive) and its conversion to other sectors (negative) in TWh_e/year as a function of SCC

In the absence of SCC, fossil gas dominates the gas supply side (Figure 5). Half of the fossil gas is used for heat production while the other half is used in the electricity and transport sectors. As the social cost of carbon increases, gas for heat and electricity production falls steeply, leading to a decrease in fossil gas consumption from 808 TWh_{th}/year to 302 TWh_{th}/year. For €200/tCO₂ the gas supply becomes fully decarbonized and biogas from methanization replaces fossil gas (152 TWh_{th}/year). While from this SCC value upwards, gas is used very little by the heat and transport sectors, by increasing the SCC value, gas production from pyro-gasification of biomass becomes cost-effective enough to be sent to CCGT power plants fitted with CCS to provide negative carbon-emitting electricity. Methanation (Power-to-gas) can provide up to 41 TWh_{th}/year of synthetic gas. When the renewable gas supply is added, the gas network can supply 270 TWh_{th}/year of energy.

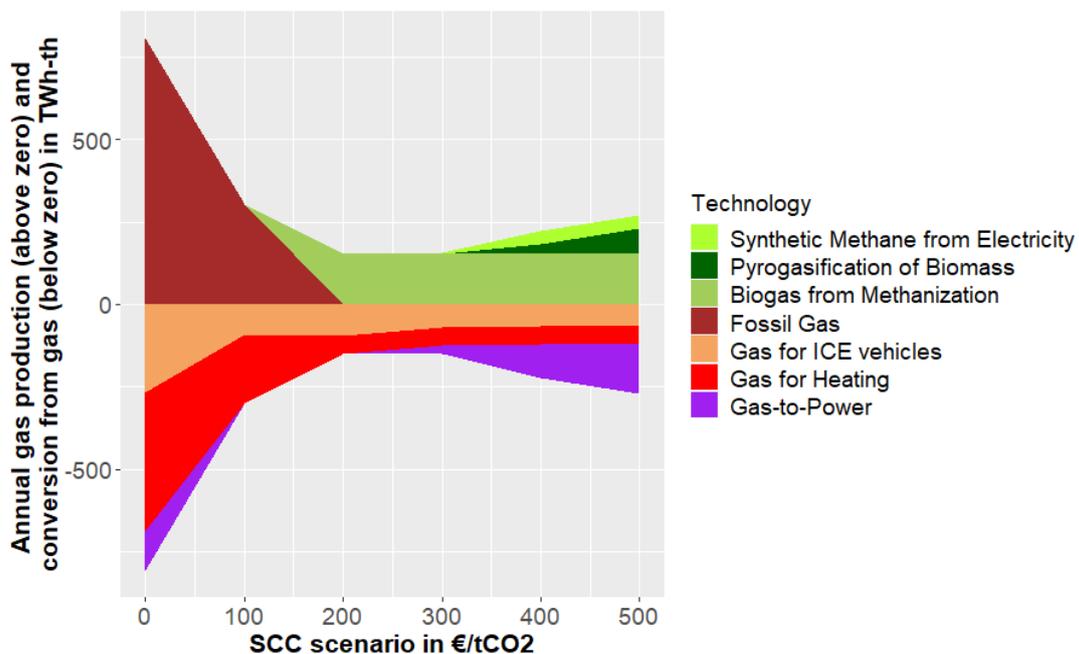


Figure 5. Gas production (positive) and its conversion to other sectors (negative) in TWh_{th}/year as a function of SCC

Figure 6 shows annual heat production as a function of SCC. For zero SCC more than 80% of the heat is produced from gas which accounts for more than 90% of energy source consumption, while by increasing the SCC value the proportion of electric heating (mostly electric heat pumps) increases remarkably (to 60% for an SCC of €100/tCO₂). From an SCC of €200/tCO₂ upwards, gas provides only 44.2 TWh_{th} which corresponds to high temperature heating, which by our assumptions cannot be electrified. **The impact of electrification on energy efficiency can be seen in Figure 5.b where electrification of low- and mid-temperature heating leads to a nearly two-fold reduction in the energy consumption for heat supply.**

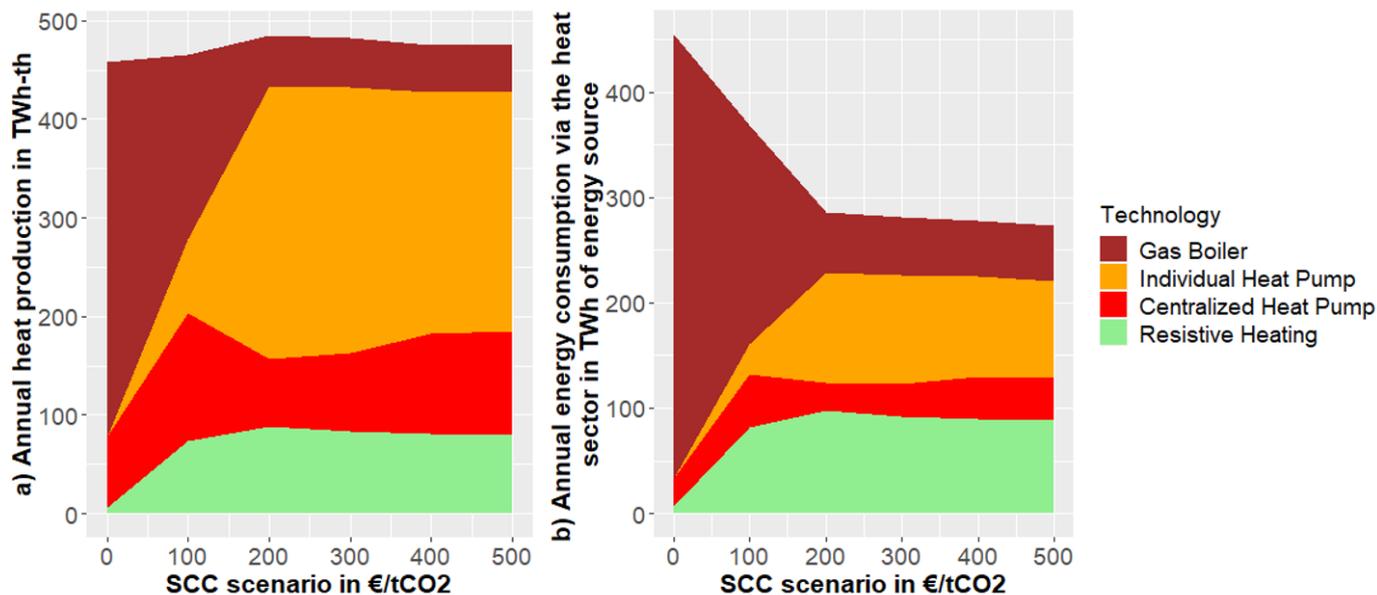


Figure 6. Annual (a) heat production in TWh_{th}/year and (b) energy consumption by heat source as a function of SCC

Likewise, as the SCC value increases the transport sector becomes highly electrified. However, heavy transport remains highly dependent on internal combustion engines (ICE) using fossil gas (for SCCs of 0 and €100/tCO₂) or renewable gas (for SCC of €200/tCO₂ and above) as the main energy carrier (Figure 7). While most of the heavy vehicles and buses (public transport except trains) are ICE vehicles, light vehicles are nearly fully electrified from an SCC of €100/tCO₂ and above. **The impact of efficiency gains thanks to electrification of light transport can be seen in Figure 7.b, where the energy consumption by transport sector decreases to nearly half of its initial gas-dependant energy consumption level.**

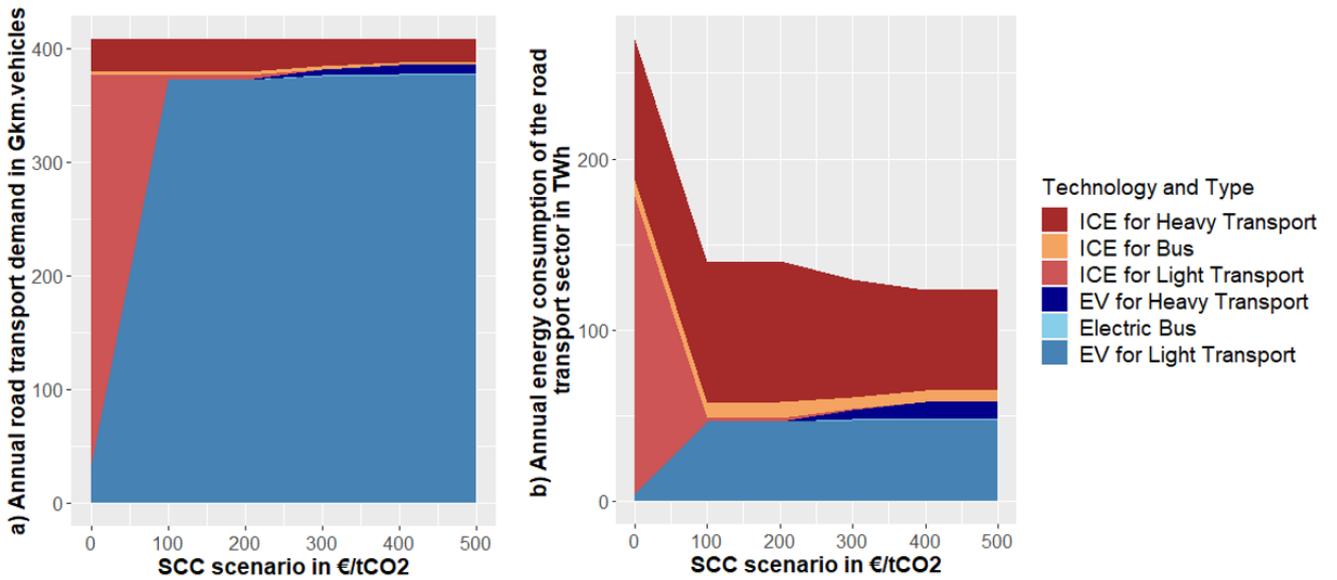


Figure 7. (a) Annual demand for road transport and (b) the energy consumption of the transport sector by mobility type and vehicle technology type in TWh/year as a function of SCC (transport by rail is not represented since it is assumed fully electrified whatever the SCC)

3.2. Cost and emissions

We define two different system costs: the technical cost (eq. (A.1) in Appendix A excluding the last part) and the social cost, i.e., the cost including the social cost of carbon (the whole of eq. (A.1)). In the EOLES_mv model, the social cost is optimized while the technical cost is calculated without optimization. In a decentralized equilibrium, the gap between these two costs would include the remuneration of negative CO₂-emitting plant operators and the tax paid by CO₂-emitting sources.

Positive and negative emissions are valued at the same price. Therefore, a carbon neutral system has equal technical and social costs while for a negative emission system the latter are lower. The intersection between the technical and social cost curves is at an SCC of nearly €200/tCO₂ while increasing the SCC value, leading to negative emissions, increases the gap between these two curves to €12bn/year (nearly 16% of the technical cost) for an SCC scenario of €500/tCO₂ (Figure 8).

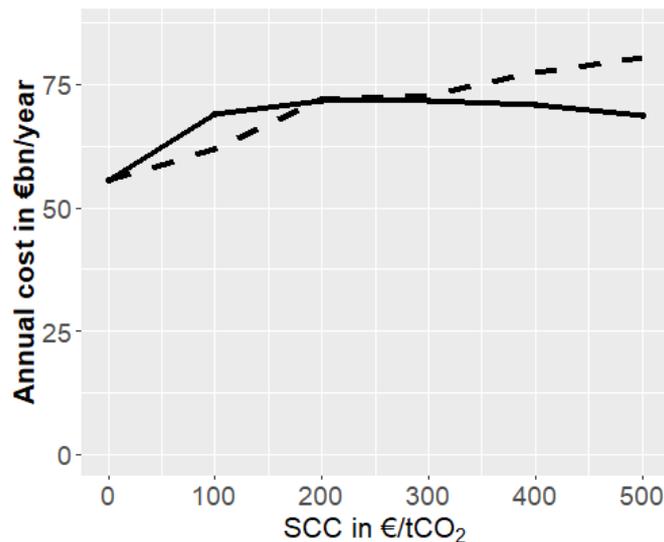


Figure 8. Annual social (including SCC) and technical costs for each SCC scenario; the dashed line represents the technical cost, and the solid line represents the optimized cost including the SCC value

Emissions are presented in Figure 9. With no SCC, the optimal energy system emits nearly 190tCO₂/year¹. Increasing the SCC to €100/tCO₂ leads to nearly a three-fold reduction in CO₂ emissions, and an SCC of €200/tCO₂ leads to carbon-neutrality in the energy system. Further increasing the SCC leads to negative emissions, which can reach up to -25tCO₂/year.

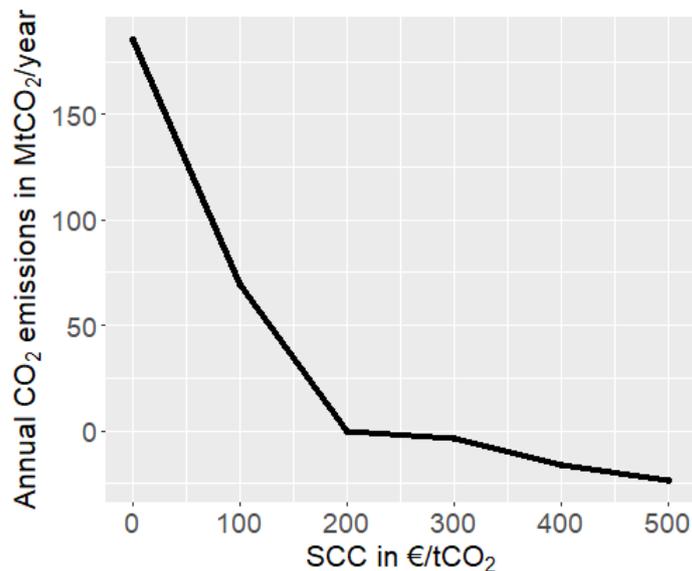


Figure 9. Annual CO₂ emissions for each SCC scenario

3.3. Availability of different low-carbon technologies

In order to study the importance of each energy production technology, four alternative availability scenarios are studied: without nuclear (green), without CCS (brown), without renewable gas (dark blue) and without variable renewable electricity (violet). The central scenario with all technologies included is represented by the dashed black. The overall CO₂ emissions and the overall energy supply-side cost are compared to evaluate the relative importance of these technologies (Figure 10).

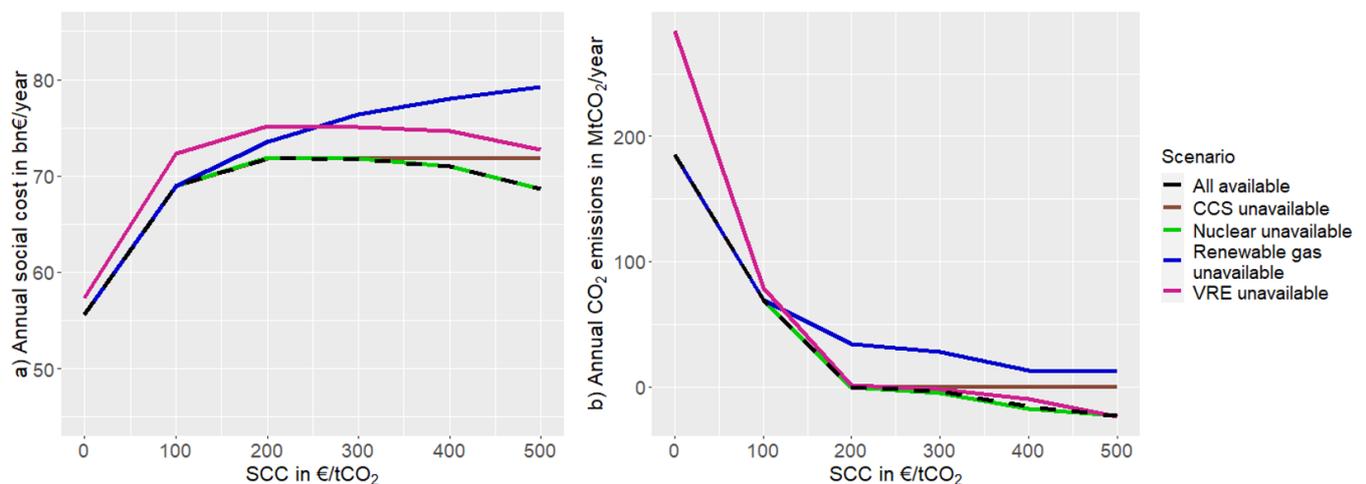


Figure 10. a) Annual social cost and b) annual CO₂ emissions of the energy systems for different technology availability scenarios

¹ Current French CO₂ emissions are around 420MtCO₂/year. The reason for this big difference in the absence of an SCC value is explained in Appendix G.

The most striking result is that excluding nuclear (the green curve) has almost no impact (less than 1%) on cost and emissions, whatever the SCC. In other words, nuclear can easily be substituted by more renewables, or by CCS.

This is not the case for the other technologies considered, but the impact of their exclusion depends on the SCC. Excluding variable renewables, i.e., wind and PV (the purple curve) brings a higher social cost (up to 6%), especially when the SCC is high, and higher emissions, especially without an SCC. In the latter case, renewables are substituted by fossil gas, which is relatively cheap but emits CO₂. Hence, variable renewables are important, whatever the SCC.

Excluding renewable gas (from methanization and pyro-gasification, the blue curve) generates an extra cost (up to 15%) and extra emissions, but only for an SCC of €200/tCO₂ or higher, since at lower values, renewable gas is not used anyway. Moreover, this scenario does not achieve climate neutrality, whatever the SCC. Carbon neutrality cannot be achieved without renewable gas since high temperature heating requires combustion, and heavy transport and buses are never fully electrified.

Finally, excluding CO₂ capture (the brown curve) entails an extra cost only for a high SCC (€400 or €500/tCO₂). Since the only negative emission technology considered is CCS combined with CCGT power plants, the scenario with no CCS means that there cannot be negative emissions, whatever the SCC.

The primary energy production and the energy mix for each end-use demand are presented in Appendix H.

3.4. Sensitivity to the cost of emerging technologies

For all the availability scenarios including renewable gas, an SCC of €200/tCO₂ is enough to completely decarbonize the energy sector (Figure 10.b). The impact of some other uncertain hypotheses such as the cost of emerging technologies should be studied to assess the robustness of this result.

To study a possible wide variation in the future cost of key emerging technologies, we varied the cost of variable renewable electricity, renewable gas supply, nuclear power, Li-Ion batteries (for both stationary use and electric vehicles) and fossil gas supply by +/-50% from the central cost scenario (presented in Tables 2, 3, 4 and 5). Figure 10 shows a) the annualized social cost and b) the annual CO₂ emissions of the energy system for SCC values of €200/tCO₂ and €300/tCO₂.

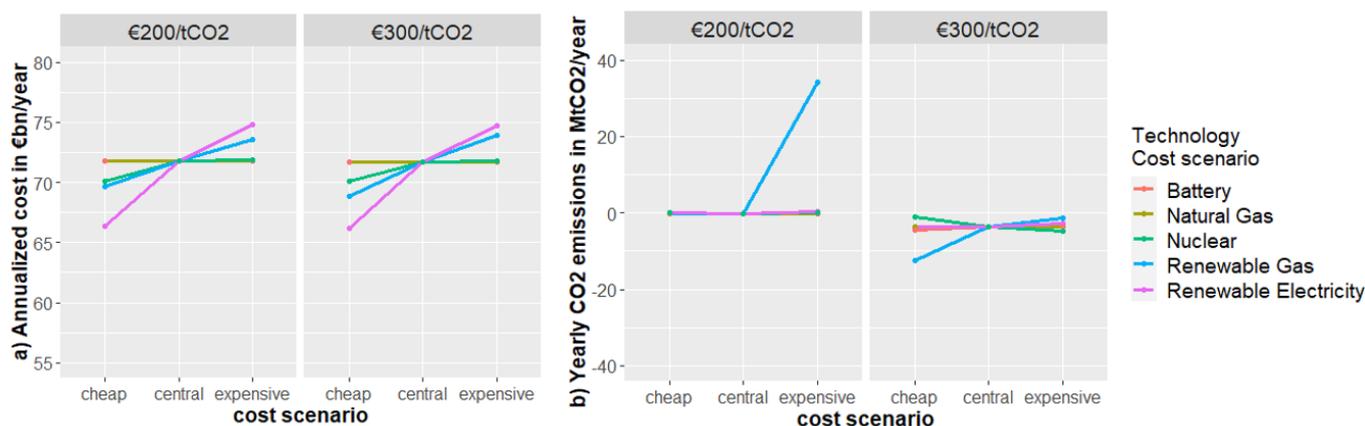


Figure 11. Sensitivity of (a) the annualized social cost and (b) energy system emissions to a +/-50% cost variation in battery (for both stationary and electric vehicles), fossil gas, nuclear energy, renewable gas, and variable renewable electricity technologies

The cost of fossil gas does not significantly impact either the social cost or CO₂ emissions, because at the SCC considered in Figure 11 (€200 and €300/t CO₂), the pre-tax cost of gas is minor compared to the value of the CO₂ emissions generated by its combustion. The cost of batteries is also of minor importance, presumably due to its small contribution to the overall cost.

The cost of variable renewable electricity technologies, renewable gas and, to a lesser extent, nuclear power has a discernible impact on the social cost (Figure 11.a), the exception being the expensive scenario for nuclear, which has almost no impact. The last result is consistent with the fact, presented in the previous section, that excluding nuclear (in the central cost scenario) has almost no impact on the social cost.

The impact of the technology cost scenarios on CO₂ emissions differs with the SCC. At €200/tCO₂, emissions stay at zero except if renewable gas technologies are expensive, in which case they reach almost 30 Mt CO₂, missing the climate neutrality target. At €300/tCO₂, emissions remain below zero for every technology cost scenario, and in the cheap renewable gas scenario, sizeable negative emissions (slightly above 10 Mt CO₂) occur.

4. Discussion

4.1. Comparison with existing scenarios

The second French “National Low-Carbon Strategy” (SNBC) proposes very high electrification rates for the transport and heating sectors [4]. Great efficiency improvements in the residential and tertiary sectors and modal change strategies in the transport sector, as well as the elimination of coal from industry, are the main enablers of the French energy transition in this scenario. Similarly, ADEME’s update of the “Energy-Climate Scenario 2035-2050” study shows an energy mix consisting of 49% to 69% renewable energies with the remainder from conventional energy resources [3]. According to this scenario, 39% of final energy consumption is satisfied by the electricity network, 24% by the gas network, 8% by the heat network and 24% from direct use of renewable energies such as biomass.

According to the “négaWatt scenario”, 35% of final energy consumption is provided by the electricity network, 36% by the gas network and 7% by the heat network [5]. The remaining 22% consists of solid and liquid fuel. In the final energy mix of this scenario no conventional energy production technology appears (oil, coal, fossil gas and nuclear energy). According to both SNBC and ADEME,

the transport sector will be highly electrified, while négaWatt suggests a less electrified transport sector. Table 6 shows the percentage of different energy carriers in France’s final energy consumption by 2050, for each of the three abovementioned national scenarios and the findings of this study.

Table 6. The percentage of each of the main energy carriers in France’s final energy consumption by 2050 for different national scenarios

Scenario	Electricity	Gas	Heat network	Direct use/Others
<i>SNBC [4]</i>	56.9%	12.6%	5.1%	25.4%
<i>ADEME [3]</i>	39%	24%	8%	24%
<i>négaWatt [5]</i>	35%	36%	7%	22%
This study (SCC=€300/tCO₂)	63.9%	19.7%	10.9%	5.5% (hydrogen)

By making the choice of energy carrier endogenous for different end-uses we conclude that in optimal scenarios, the energy system will be highly electrified. Up to 80% of a carbon neutral energy system’s primary energy production comes from electricity. The transport sector is presented as a highly electrified sector in the ADEME and SNBC scenarios. Our findings show that although the light transport sector is fully electrified, even for very high SCC scenarios the heavy transport sector remains highly dependent on internal combustion engines, with 29% of electric vehicles in the final heavy transport demand. These findings are in line with both the ADEME ([3]) and SNBC ([4]) scenarios but are very contradictory to négaWatt’s scenario which suggests 15.7% of electrification in the transport sector [5].

Sector-coupling can accelerate the decarbonization of the energy sector and decrease the costs and load curtailment providing additional flexibility [20], [21], [47], [48]. Our findings, which agree with this conclusion, highlight the importance of full endogeneity in energy carrier choice including the key representative technologies that make this choice possible. Brown et al. show that with no commercial power exchange with neighbouring countries, more than 80% of France’s primary energy consumption is satisfied by VRE resources, and only about 5% of this primary energy is provided by fossil gas [20]. This study excludes renewable gas as a possible energy supply option. While our findings for SCC values of €200/tCO₂ and above are very close to these results, fossil gas is abandoned at these SCC values. Our findings show that in an optimal case a significant proportion of future heavy transport demand is met by gas-powered internal combustion engines, and a small proportion by electric vehicles. In a scenario where electric vehicles alone satisfy transport demand, and fossil gas alone is available as a gas production option, the proportion of gas in the final energy demand would be lower.

4.2. The cost of carbon-neutrality

A nearly carbon-neutral energy system requires an SCC of €200/tCO₂ for the central cost scenario. Under a pessimistic cost scenario (especially for renewable gas technologies), it requires an SCC of €300/tCO₂. The technical costs of the optimal energy system for these SCC values are €71.84bn/year and €72.83bn/year respectively. In the absence of an SCC value, the optimal energy system costs €55.6bn/year. The difference between the cost of a carbon-neutral energy system (for an SCC of €300/tCO₂) and one without SCC is thus €17.23bn/year. France’s gross domestic product (GDP) was €2,332.68bn/year in 2019¹. Assuming an average increase in GDP of 1%/year, in 2050 France’s GDP would be €3,175.54bn/year. The 2050 energy system for zero SCC would cost 2.29% of this

¹ <https://tradingeconomics.com/france/gdp>

estimated annual GDP. Considering the technical cost of a decarbonized national energy system, decarbonization would cost about 0.54% of France's estimated GDP for 2050, a reasonable price to pay to achieve carbon neutrality in the energy sector.

According to the French ministry for the Ecological Transition, France spent €167.8bn during 2019 to satisfy its energy demand which accounted for energy product imports, remuneration of internal energy-related activities in France and taxes and subsidies¹. These values are not directly comparable to our results since EOLES_mv does not take into account any taxes or subsidies, nor investments in the gas and electricity networks. However, a comparison can be made with these values by considering only remuneration of internal activities in France (mostly electricity and renewable energy production, operation and maintenance of gas and electricity networks, fuel distribution and refinery activities for petroleum products) and imports by adding possible network development extension costs to them. Remuneration of internal activities and expenditure on energy-related imports account for €115.2bn/year. According to the French electricity transmission network operator, an annualized cost of the transport and distribution network (including adaptation of the electricity system to renewable energy development) for a carbon-neutral power system would be of the order of €23bn/year [36]. Moreover, according to the same study, development of a hydrogen network (including storage) would represent 20% of the levelized cost of hydrogen (from the same study, the levelized cost of hydrogen is 120€/MWh_{th}). Thus, for a hydrogen demand value of 40TWh_{th} the infrastructure cost of the hydrogen network and storage system can be considered as €1bn/year. Assuming no further gas network development and adding the cost of power grid stability measures of €0.8bn/year to these figures, the comparable cost of our carbon-neutral energy system with current energy expenditure becomes roughly €98bn/year, which is less than the 2019 value of roughly €115bn/year. This cost reduction is obtained thanks to efficiency gains via electrification, complete elimination of energy product imports and limited energy-saving measures that are considered in the French National Low-Carbon Strategy.

4.3. The role of renewable gas

Our findings show that while the proportion of renewable gas remains much lower than that of renewable electricity in primary energy production, it is of the utmost importance. In the absence of renewable gas, the energy system cannot achieve carbon neutrality even for a high SCC value of €500/tCO₂. Moreover, our sensitivity analysis confirms that the cost of renewable gas technologies impacts both the social cost and the CO₂ emission level more than the cost of the other technologies considered.

Although our findings imply that renewable gas is of key importance in achieving carbon-neutrality for the lowest cost, using the existing gas infrastructure for biogas transmission and distribution might lead to methane leakage [49], eroding all the associated climate benefits [50]. **Thus, our findings call for reinforcement of both gas transmission and distribution networks to limit the effect of methane leakage.**

Similarly, particulate pollution by gas-fuelled ICE vehicles has been highlighted as an important environmental disadvantage of this transport technology [51]. Therefore, it is essential to limit methane leakage and particulate pollution and take them into account correctly in environmental impact assessments.

¹ <https://www.statistiques.developpement-durable.gouv.fr/chiffres-cles-de-lenergie-edition-2021>

In this study, we have chosen gas-fuelled ICEs as a representative technology for all ICE vehicles since they have similar economic characteristics and the main difference between them would be the relative cost of these fuels. Therefore, the idea of gas being the carrier for transport fuel can be expanded to include liquid biofuels and liquefied biogas. However, the environmental damage caused by biofuel production and its high energy demand, as well as the competition between biofuels and food crops (due to land-use changes caused by biofuel production) are highly debated topics casting doubt on scenarios that include liquid biofuels [52], [53], [54], [55].

4.4. Negative emissions

From an SCC of €200/tCO₂ upwards, the energy system can provide negative emissions, and for an SCC of €500/tCO₂ the negative emissions reach nearly 24MtCO₂/year. ***Such a negative emission level can be translated into €12bn/year of remuneration for negative emission providers.*** In the second French National Low-Carbon Strategy report, the residual emissions for France are evaluated at more than 80MtCO_{2eq}/year (Mainly N₂O and CH₄ from agriculture), to be offset by negative emissions [4]. These emissions are not covered by the EOLES_mv model but negative emissions from the energy sector could be one of the compensation options to help achieve net zero emissions by 2050. Thus, although from an energy-only modelling perspective achieving carbon-neutrality does not necessarily require carbon capture and storage, in order to deal with the residual emissions, carbon capture and storage combined with bio-energies represent a pivotal mitigation option as stated in the IPCC's *Special Report on 1.5°C of Global Warming* [56] and in the IEA's *Special Report on Carbon Capture, Utilisation and Storage* [57].

4.5. Limits and further research

In this paper, we have considered France in isolation which means there is no exchange of energy between France and its neighbouring countries (except fossil gas imports). While France is currently the largest net electricity exporter in Europe, net exports are on a downward trend: 43 TWh in 2021 vs. 60 TWh in 2018. The high level of exports from France in recent years was due to its large nuclear fleet, itself built in response to overestimated electricity demand forecasts, and most prospective studies forecast that net exports will be only slightly positive in 2050. Several findings of this study might be different in a highly inter-connected European energy system. For example, renewable gas can play an important role in balancing wind fluctuations, but interconnections with neighbouring countries can also help balance intermittent power production technologies. Therefore, the role of renewable gas would be less important, at least in the electricity sector. On the other hand, we consider only anaerobic digestion of organic waste and pyro-gasification of wood and biomass as sources of bioenergy, which would only be used by injection into the gas network to satisfy either transport, heating or electricity final end-uses. Renewable gas can also be used as a raw material in several industries, and its by-products also have an economic value. Thus, a more detailed analysis of the whole bio-methane value chain considering different production and end-use options could be the next step in evaluating the importance of renewable gas in a carbon-neutral energy system. However, as explained in section 4.3, methane leakage and particulate pollution resulting from the increased use of renewable gas in the energy sector could erode all the assumed benefits. The direct and indirect environmental impacts of renewable gas production, distribution and consumption need further analysis.

This study uses inelastic end-use demand profiles. The energy demand scenario from the French low-carbon strategy that we have used is based on significant efforts being made to achieve energy efficiency and a modal shift in different sectors. Although these assumptions may be realistic for high SCC values, the situation will be very different for low SCC values (especially 0€/tCO₂ and 100€/tCO₂), leading to different final energy demand levels and profiles in different sectors. By

including the option of weekly charging for EVs and ICE vehicles, we accounted for the elasticity of weekly charging profiles in the transport sector, but the energy demand profiles of other sectors are all inelastic in EOLES_mv. Therefore, the energy demand profiles, and the annual end-use demand levels are likely to be different for different SCC values not only in the transport sector, but in all other energy sectors. Inclusion of this elasticity in the energy system modelling, although very challenging, would lead to energy demand profiles that are better adapted to variable energy supply technologies, leading to lower energy system costs.

The EOLES_mv model considers France as an isolated country with no interconnections with neighbouring countries. This assumption can lead to a lower proportion of variable renewable electricity supply sources such as wind and solar power technologies. Interconnections with neighbouring countries can significantly reduce both the cost and the price volatility of the power system, leading to lower energy system costs [20, 73]. Therefore, an integrated Europe-wide study connecting all the main energy networks could be a further extension of this study and is very likely to reinforce this study's conclusions. However, the current version of the EOLES_mv model is computationally demanding, with a single scenario simulation time of 4 days. Therefore, such a study might require many simplifications on the model in order to maintain computational tractability.

5. Conclusion and policy implications

This article studies the cost-optimal low-CO₂ energy mix, relative role of energy carriers and different low-carbon options applied to the case of France for the year 2050. To that end, we have developed a first-of-its-kind integrated model that allows for optimization of the energy system (EOLES_mv). We allowed the end-use demand for each major energy-consuming sector to choose endogenously among four different energy carriers (electricity, heat, gas and hydrogen), we maintained high temporal resolution, and we studied different availability and future cost development scenarios for the key low-carbon technologies as a function of the SCC.

Our results imply that the optimal carbon-neutral energy system is highly electrified (up to 80% of the primary energy supply), but that renewable gas, even though accounting for a smaller proportion of energy supply, plays a very important role in emission reductions. In the presence of renewable gas, a carbon-neutral energy sector can be achieved for an SCC of €200/tCO₂, while for unfavourable conditions in the future cost reduction of renewable gas, carbon neutrality can be achieved for an SCC of €300/tCO₂. If renewable gas is not available, carbon-neutrality cannot be achieved even for the very high SCC of €500/tCO₂.

Renewable electricity and gas technologies play a crucial role in achieving carbon-neutrality, and their absence from the energy supply side would lead to significant extra cost and emissions. Conversely, exclusion of nuclear energy from the energy supply side has a minor impact on both emissions and cost. Therefore, one important policy-related outcome of this study is to invest in renewable gas and variable renewable electricity production technologies, and to prioritize them over other low-carbon options, particularly nuclear energy. ***This conclusion is timely since the French prime minister has recently announced that a large public debate on energy choices will take place after the June 2022 legislative elections¹.***

Finally, our results suggest that, in a cost-optimal coupled energy system, electricity would satisfy the demand for low- and mid-temperature heat and light transport, while gas would satisfy that for

¹ <https://www.lemoniteur.fr/article/grand-debat-national-sur-le-nucleaire-apres-les-legislatives.2193937>

heavy transport and high temperature heat (>300°C). Therefore, this study suggests further development of electric vehicle and gas charging stations, as well as individual and central heat pumps.

This study could be extended in at least three directions. First, adding a more detailed representation of the industry and transport sectors may generate a more precise assessment of the substitutions among energy carriers. Second, a more detailed analysis of hydrogen production and consumption may bring useful insights. For instance, if hydrogen demand is very high, wind and solar energy deployment limits may become binding, which may impact the whole energy system. Third, while energy demand is partly endogenous in our model since energy efficiency differs across energy carriers, this could be developed further by including other sources of energy efficiency, as well as energy sufficiency, i.e. an endogenous level of energy services (e.g., number of passenger-km in the transport sector, or indoor temperature for the heating sector).

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Appendices

Appendix A. EOLES_mv model

A.1. Sets and parameters

Table A.1 presents the sets and indices of the EOLES_mv model and Table A.2 the parameters. Throughout the paper, every energy unit (e.g. MWh) or capacity unit (e.g. MW) is expressed in useful form. For instance, some energy is converted from gas to electricity by OCGT. The input energy in MWh is in the gas carrier, therefore the unit is MWh_{th} and conversion efficiency by OCGT is 45%. The output energy is in MWh_e equivalent to the value in MWh_{th} multiplied by 0.45.

table A. 1 Sets and indices of the EOLES_mv model

Index	Set	Description
h	$\in H$	Hour: the number of hours in a year, from 0 to 8759
d	$\in D$	Day: The number of days in a year, from 1 to 365
w	$\in W$	Week: The number of weeks in a year, from 1 to 52 (the 52 nd week accounts for 10 days)
m	$\in M$	Month: the twelve months, from January to December
tec	$\in TEC$	Technologies: The set of all energy supply, conversion, storage and non-existing carrier technologies (floating offshore, monopile offshore, onshore, PV, river, lake, nuclear, fossil gas, methanization, pyro-gasification, OCGT, CCGT, CCGT with CCS, electrolysis, methanation, heat network, resistive heating, electric heat pump, gas heat pump, central boiler, decentralized boiler, heavy EV, light EV, EV bus, train, heavy ICE, light ICE, ICE bus, PHS, battery, gas storage, individual thermal energy storage -ITES- and central thermal energy storage -CTES)
gen	$\in GEN \subseteq TEC$	Generation: Energy supply technologies (floating offshore, monopile offshore, onshore, PV, river, lake, nuclear, fossil gas, methanization and pyro-gasification)
$elec$	$\in ELEC \subseteq TEC$	Electricity: The technologies providing electricity by supply, conversion or storage (floating offshore, monopile offshore, onshore, PV, river, lake, nuclear, OCGT, CCGT, CCGT with CCS, PHS and battery)
gas	$\in GAS \subseteq TEC$	Gas: The technologies providing gas by supply, conversion or storage (fossil gas, methanization, pyro-gasification, electrolysis, methanation and gas storage)
$heat$	$\in HEAT \subseteq TEC$	Heat: The technologies providing heat by conversion and storage (resistive heating, electric heat pump, gas heat pump, central boiler, decentralized boiler, individual thermal energy storage and central thermal energy storage)
$heat_{low}$	$\in LOWHEAT \subseteq HEAT$	Low temperature Heat: The technologies providing low temperature heat by conversion and storage (heat network, resistive heating, electric heat pump, gas heat pump, central boiler, decentralized boiler, individual thermal energy storage and central thermal energy storage)
$heat_{mid}$	$\in MIDHEAT \subseteq HEAT$	Mid temperature Heat: The technologies providing mid temperature heat by conversion and storage (resistive heating and decentralized boiler)
$heat_{high}$	$\in HIGHHEAT \subseteq HEAT$	High temperature Heat: The technologies providing mid temperature heat by conversion and storage (decentralized boiler)
hp	$HPC \subseteq HEAT$	Heat Pump: set to group two heat pump technologies (centralized and decentralized)
$transport$	$\in TRANSPORT \subseteq TEC$	Transport: The technologies that meet different types of transport demand (heavy EV, light EV, EV bus, train, heavy ICE, light ICE and ICE bus)
gen_{elec}	$\in ELEGEN \subseteq ELEC$	Electricity supply: The technologies generating electricity (floating offshore, monopile offshore, onshore, PV, river, lake and nuclear)
gen_{gas}	$\in GASGEN \subseteq GAS$	Gas supply: Technologies supplying gas (fossil gas, methanization and pyro-gasification)

$biogas_{gas}$	$\in \text{BIOGAS} \subseteq \text{GAS}$	Renewable gas: biogas supply technologies (methanization and pyro-gasification)
vre	$\in \text{VRE} \subseteq \text{ELEC}$	VRE: variable renewable electricity generation technologies (offshore, onshore, PV and run-of-river)
str	$\in \text{STR} \subseteq \text{TEC}$	Storage: energy storage technologies (PHS, battery, gas storage, individual thermal energy storage and central thermal energy storage)
str_{elec}	$\in \text{STRELEC} \subseteq \text{ELEC}$	Electric storage: technologies providing storage for electricity (battery and PHS)
str_{gas}	$\in \text{STRGAS} \subseteq \text{GAS}$	Gas storage: technologies providing storage for gas (gas storage)
str_{heat}	$\in \text{STRHEAT} \subseteq \text{HEAT}$	Heat storage: technologies providing storage for heat (ITES and CTES)
$conv$	$\in \text{CONV} \subseteq \text{TEC}$	Conversion: energy vector-change technologies (OCGT, CCGT, CCGT with CCS, electrolysis, methanation, resistive heating, electric heat pump, gas heat pump, central boiler and decentralized boiler)
$conv_{elec}$	$\in \text{CONVELEC} \subseteq \text{TEC}$	Conversion from electricity: energy vector-change technologies from electricity to other vectors (electrolysis, methanation, resistive heating and electric heat pump)
$conv_{gas}$	$\in \text{CONGAS} \subseteq \text{TEC}$	Conversion from gas: energy vector-change technologies from gas to other vectors (OCGT, CCGT, CCGT with CCS, gas heat pump, centralized boiler and decentralized boiler)
$central$	$\in \text{CENTRAL} \subseteq \text{HEAT}$	Central heating: heating technologies needing heat network (electric heat pump, gas heat pump and centralized boilers)
$vector_t$	$\in \text{TVECTOR}$	Transport vector: two different engine types for transport sector (EV and ICE)
cat_t	$\in \text{TCAT}$	Transport category: four categories of transport demand (heavy, light, bus and train)
$ev_{transport}$	$\in \text{EV} \subseteq \text{TRANSPORT}$	Electric transport: the electric transport technologies (heavy EV, light EV, EV bus and train)
$ice_{transport}$	$\in \text{ICE} \subseteq \text{TRANSPORT}$	Gas transport: the ICE transport technologies using gas as fuel (heavy ICE, light ICE and ICE bus)
frr	$\in \text{FRR} \subseteq \text{TEC}$	Frequency restauration reserves: Technologies contributing to secondary reserves requirements (lake, PHS, battery, OCGT, CCGT, CCGT with CCS and nuclear)
co_2	$\in \text{CO2}$	Social cost of carbon scenario: The scenarios are 1, 2, 3, 4, 5 and 6

table A. 2 Parameters of the EOLES_mv model

Parameter	Unit	Description
day_h	[-]	A parameter to show which day each hour is in
$week_h$	[-]	A parameter to show which week each hour is in
$month_h$	[-]	A parameter to show which month each hour is in
$cf_{vre,h}$	[-]	Hourly production profiles of variable renewable energies
$profile_h^{transport}$	[-]	Hourly charging profile of each transport technology
$demand_{heat_{low},h}$	$[GW_{th}]$	Hourly low temperature heat demand profile
$demand_{heat_{mid},h}$	$[GW_{th}]$	Hourly mid temperature heat demand profile (industry)
$demand_{heat_{high},h}$	$[GW_{th}]$	Hourly high temperature heat demand profile (industry)
$demand_{hydrogen,h}$	$[GW_{th}]$	Hourly hydrogen demand profile (for industry)
$demand_{elec,h}$	$[GW_e]$	Hourly electricity demand profile

$demand_h^{heavy}$	[Gkm. vehicle]	Hourly transport demand for heavy vehicles
$demand_h^{light}$	[Gkm. vehicle]	Hourly transport demand for light vehicles
$demand_h^{bus}$	[Gkm. vehicle]	Hourly transport demand for buses
$demand_h^{train}$	[GWh _e]	Hourly transport demand for trains (flat)
$lake_m$	[GWh _e]	Monthly extractable energy from lakes
ϵ_{vre}	[-]	Frequency restoration requirement because of forecast errors on the production of each variable renewable energy
q_{tec}^{ex}	[GW _e]	Existing installed capacity by each hydroelectric technology
$annuity_{tec}$	[M€/GW/year]	Annualized investment cost of each technology
$annuity_{str}^{en}$	[M€/GWh/year]	Annualized investment cost of energy volume for storage technologies
$annuity_{transport}^{vol}$	[M€/GWh/year]	Annualized investment cost of energy reservoir volume of transport technology
$fO\&M_{tec}$	[M€/GW/year]	Fixed operation and maintenance cost
$vO\&M_{tec}$	[M€/GWh]	Variable operation and maintenance cost of each technology
η_{str}^{in}	[-]	Charging efficiency of storage technologies
η_{str}^{out}	[-]	Discharging efficiency of storage technologies
η_{conv}	[-]	Conversion efficiency for vector change technologies
cop_h^{hp}	[-]	Hourly coefficient of performance of heat pumps
$\eta_{cat_t}^{vector_t}$	[Gkm. vehicle /kWh]	Transport efficiency of each transport technology
q^{pump}	[GW _e]	Pumping capacity for Pumped hydro storage
e_{PHS}^{max}	[GWh _e]	Maximum energy volume that can be stored in PHS reservoirs
g_{biogas}^{max}	[TWh _{th}]	Maximum yearly energy that can be generated from renewable gas supply technologies
$\delta_{uncertainty}^{load}$	[-]	Uncertainty coefficient for hourly electricity demand
$\delta_{variation}^{load}$	[-]	Load variation factor
r_{nuc}^{up}	[-]	Maximal ramping up rate of nuclear power
r_{nuc}^{down}	[-]	Maximal ramping down rate of nuclear power
cf_{nuc}	[-]	The maximal annual capacity factor for nuclear power
cf_{ocgt}	[-]	The maximal annuity capacity factor for OCGT plant
cf_{ccgt}	[-]	The maximal annual capacity factor for CCGT plant

$c_{ccgt-ccs}$	[-]	The maximal annual capacity factor for CCGT with CCS plants
e_{tec}	[tCO_2/GWh]	Emission rate of each technology
scc_{CO_2}	[$€/tCO_2$]	Social cost of carbon for each SCC scenario
$\varphi_{CO_2}^{max}$	[$MtCO_2/year$]	The maximal carbon dioxide that can be stored annually
$\gamma_{methanization}^{CO_2}$	[-]	The green CO_2 available as a byproduct of methanization for methanation
$\tau^{hydrogen}$	[-]	The maximal penetration rate of hydrogen in the gas network

A.2. Variables

The variables resulting from the optimization are presented in Table A.3.

table A. 3 Variables of EOLES_mv model

Variable	Unit	Description
$G_{tec,h}$	GWh	Hourly energy generation by technology
Q_{tec}	GW	Installed capacity by technology
$STORAGE_{str,h}$	GWh	Hourly energy entering each storage technology (inflow)
$SOC_{str,h}$	GWh	Hourly state of charge of each storage technology (stock)
S_{str}	GW	Installed charging capacity by storage technology
$CONVERT_{conv,h}$	GWh	Hourly converted energy by each conversion technology
$CHARGE_{transport,h}$	GWh	Hourly charging of each transport technology
$RESERVOIR_{transport}$	GWh	The energy reservoir volume for each transport technology
$VOLUME_{str}$	GWh	Energy capacity by storage technology
$RSV_{frr,h}$	GW_e	Hourly upward frequency restoration requirement to manage the variability of renewable energies and demand uncertainties
$COST$	$b€$	Total energy system cost annualized (minus the investment cost of already installed capacities). This is the objective function to be minimized.

A.3. Equations

A.3.1. Objective function

The objective function, shown in Equation (A.1), is the sum of all costs over the chosen period, including the annualized investment costs as well as the fixed and variable O&M costs. For some storage options, another CAPEX-related cost proportional to the energy capacity in $€/kWh$ is accounted for ($annuity_{str}^{en}$).

$$COST = \left(\sum_{tec} [(Q_{tec} - q_{tec}^{ex}) \times annuity_{tec}] + \sum_{str} (VOLUME_{str} \times annuity_{str}^{en}) + \sum_{tec} (Q_{tec} \times f_{O\&M_{tec}}) + \sum_{tec} \sum_h (G_{tec,h} \times (v_{O\&M_{tec}} + e_{tec} scc_{CO_2})) \right) / 1000 \quad (A.1)$$

where Q_{tec} represents the production capacities, q_{tec}^{ex} represents the existing capacity (notably for hydro-electricity technologies with long lifetime), $VOLUME_{str}$ is the energy storage capacity in GWh, S_{str} is the storage capacity in GW, $annuity$ is the annualized investment cost, $fO\&M$ and $vO\&M$ respectively represents fixed and variable operation and maintenance costs, $G_{tec,h}$ is the hourly generation of each technology, e_{tec} is the specific emission of each technology in tCO_2/GWh of power production and SCC_{CO_2} is the social cost of carbon in $\text{€}/tCO_2$.

A.3.2. Adequacy equations

Energy demand must be met for each hour. If energy production exceeds energy demand, the excess energy can be either sent to storage units or curtailed (equations A.2, A.3, A.4a-c, A.5a-d and A.6).

$$\sum_{elec} G_{elec,h} \geq demand_{elec,h} + \sum_{str_{elec}} STORAGE_{str_{elec},h} + \sum_{conv_{elec}} CONVERT_{conv_{elec},h} + \sum_{ev} CHARGE_{ev,h} \quad (A.2)$$

$$\sum_{gas} G_{gas,h} \geq \sum_{str_{gas}} STORAGE_{str_{gas},h} + \sum_{conv_{gas}} CONVERT_{conv_{gas},h} + \sum_{ice} CHARGE_{ice,h} + demand_{hydrogen,h} \quad (A.3)$$

$$\sum_{heat} G_{heat_{low},h} \geq demand_{heat_{low},h} + \sum_{str_{heat_{low}}} STORAGE_{str_{heat_{low}},h} \quad (A.4a)$$

$$\sum_{heat} G_{heat_{mid},h} \geq demand_{heat_{mid},h} \quad (A.4b)$$

$$\sum_{heat} G_{heat_{high},h} \geq demand_{heat_{high},h} \quad (A.4.c)$$

$$G_{heavy_t,h} \times \eta_{heavy_t}^{vector_t} = demand_{transport,h}^{heavy_t} \quad (A.5a)$$

$$G_{light_t,h} \times \eta_{light_t}^{vector_t} = demand_{transport,h}^{light_t} \quad (A.5b)$$

$$G_{bus,h} \times \eta_{bus_t}^{vector_t} = demand_{transport,h}^{bus_t} \quad (A.5c)$$

$$G_{train_t,h} \times \eta_{train_t}^{ev_t} = demand_{transport,h}^{train_t} \quad (A.5d)$$

$$G_{electrolysis,h} = STORAGE_{hydrogen,h} + demand_{hydrogen,h} - G_{hydrogen,h} + CONVERT_{OCGT-H_2} \quad (A.6)$$

Where $G_{elec,h}$, $G_{gas,h}$, $G_{heat_{low},h}$, $G_{heat_{mid},h}$, and $G_{heat_{high},h}$ is the energy produced by electricity, gas and low, mid and high temperature heat technologies at hour h and $STORAGE_{str_{elec},h}$, $STORAGE_{str_{gas},h}$, $STORAGE_{str_{heat_{low}},h}$ is the energy entering storage electricity, gas and heat storage technologies at hour h . $CONVERT_{conv_{elec},h}$ is the energy conversion from electricity to other vectors and $CONVERT_{conv_{gas},h}$ is the energy conversion from gas to other vectors at hour h and $CHARGE_{ice,h}$ is the charging of internal combustion engine vehicles and $CHARGE_{ev,h}$ is the charging of electric vehicles at hour h . For each transport category the energy demand in vehicle.km should be satisfied either by ev or ice as transport energy vector options ($vector_t$), and the conversion from the energy in the gas or electricity form to the demand by transport category ($demand_{transport,h}^{heavy_t}$, $demand_{transport,h}^{light_t}$ and $demand_{transport,h}^{bus_t}$) in vehicle.km is done by the vehicle efficiency changing by both the energy vector and the transport category; $\eta_{cat_t}^{vector_t}$. We only consider the electricity to satisfy the trains' demand.

According to [58], the coal demand for steel industry can be replaced by hydrogen. Similarly, several other industrial processes can be decarbonized by inclusion of hydrogen as a primary material to the

industrial processes [59]. Therefore, we define an hourly hydrogen demand for the industry ($demand_{hydrogen,h}$) which should be satisfied (Equation A.6) beside other adequacy equations.

A.3.3. Variable renewable power production

For each variable renewable energy (VRE) technology, for each hour, the hourly power production is given by the hourly capacity factor profile multiplied by the installed capacity available (Equation A.7).

$$G_{vre,h} = Q_{vre} \times cf_{vre,h} \quad (A.7)$$

Where $G_{vre,h}$ is the energy produced by each VRE resource at hour h , Q_{vre} is the installed capacity and $cf_{vre,h}$ is the hourly capacity factor.

A.3.4. Energy storage

Energy stored by storage option str at hour $h+1$ is equal to the energy stored at hour h plus the difference between the energy entering and leaving the storage option at hour h , accounting for charging and discharging efficiencies (Equation A.8):

$$SOC_{str,h+1} = SOC_{str,h} + (STORAGE_{str,h} \times \eta_{str}^{in}) - \left(\frac{G_{str,h}}{\eta_{str}^{out}}\right) \quad (A.8)$$

Where $SOC_{str,h}$ is the state of charge of the storage option str at hour h , while $\eta_{str}^{in} \in [0,1]$ and $\eta_{str}^{out} \in [0,1]$ are the charging and discharging efficiencies.

A.3.5. Secondary reserve requirements

Three types of operating reserves are defined by ENTSO-E, depending on their activation speed [60]. The fastest reserves are Frequency Containment Reserves (FCRs), which must be able to be on-line within 30 seconds. The second group is made up of Frequency Restoration Reserves (FRRs), in turn divided into two categories: a fast, automatic component (aFRRs), also called ‘secondary reserves’, with an activation time of no more than 7.5 min; and a slow manual component (mFRRs), or ‘tertiary reserves’, with an activation time of no more than 15 min. Finally, reserves with a start-up-time beyond 15 minutes are classified as Replacement Reserves (RRs).

Each category meets specific system needs. The fast FCRs are useful in the event of a sudden break, like a line fall, to avoid system collapse. FRRs are useful for variations over several minutes, such as a decrease in wind or PV output. Finally, the slow RRs act as a back-up, slowly replacing FCRs or FRRs when the system imbalance lasts more than 15 minutes.

In the model we only consider FRRs, since they are the most heavily impacted by the inclusion of VRE. FRRs can be defined either upwards or downwards, but since the electricity output of VREs can be curtailed, we consider only upward reserves.

The quantity of FRRs required to meet ENTSO-E’s guidelines is given by equation (A.9). These FRR requirements vary with the variation observed in the production of renewable energies. They also depend on the observed variability in demand and on forecast errors:

$$\sum_{frr} RSV_{frr,h} = \sum_{vre} (\varepsilon_{vre} \times Q_{vre}) + demand_h \times (1 + \delta_{variation}^{load}) \times \delta_{uncertainty}^{load} \quad (A.9)$$

Where $RSV_{frr,h}$ is the required hourly reserve capacity from each of the reserve-providing technologies (dispatchable technologies) indicated by the subscript frr ; ε_{vre} is the additional FRR requirement for VRE because of forecast errors, $\delta_{variation}^{load}$ is the load variation factor and $\delta_{uncertainty}^{load}$ is the uncertainty factor in the load because of hourly demand forecast errors. The method for calculating these various coefficients according to ENSTO-E guidelines is detailed by [61].

A.3.6. Energy-generation-related constraints

The relationship between hourly-generated energy and installed capacity can be calculated using Equation (A.10). Since the chosen time slice for the optimization is one hour, the capacity enters the equation directly instead of being multiplied by the time slice value.

$$G_{tec,h} \leq Q_{tec} \quad (A.10)$$

The installed capacity of all the dispatchable technologies should be more than the electricity generation required of those technologies to meet demand; it should also satisfy the secondary reserve requirements. Installed capacity for dispatchable technologies can therefore be expressed by Equation (A.11).

$$Q_{frr} \geq G_{frr,h} + RSV_{frr,h} \quad (A.11)$$

Monthly available energy for the hydroelectricity generated by lakes and reservoirs is defined using monthly lake inflows (Equation A.12). This means that energy stored can be used within the month but not across months. This is a parsimonious way of representing the non-energy operating constraints faced by dam operators, as in [62].

$$lake_m \geq \sum_{h \in m} G_{lake,h} \quad (A.12)$$

Where $G_{lake,h}$ is the hourly power production by lakes and reservoirs, and $lake_m$ is the maximum electricity that can be produced from this energy resource in one month.

A.3.7. Energy conversion

Energy generated by any energy conversion technology should include the conversion efficiency of the conversion technology. Equation A.13 relates the energy generation and generation by each conversion technology.

$$G_{conv,h} = \eta^{conv} \times CONVERT_{conv,h} \quad (A.13)$$

Where η^{conv} is the conversion efficiency of the energy conversion technology $conv$, and $CONVERT_{conv,h}$ is the converted energy by the same conversion technology at hour h .

We define a second conversion equation for heat pumps, where the coefficient of performance is a function of the heated sink's temperature and ambient temperature, as introduced by [20].

$$G_{hp,h} = cop_h^{hp} \times CONVERT_{hp,h} \quad (A.14)$$

Where $G_{hp,h}$ is the hourly heat supply from centralized and decentralized heat pumps and cop_h^{hp} is the hourly coefficient of performance of heat pumps.

A.3.8. Charging of transport technologies

Electric vehicles and internal combustion engine vehicles have different charging profiles. Equation (A.15) applies these charging profiles:

$$CHARGE_{transport,h} = profile_h^{transport} \times Q_{transport} \quad (A.15)$$

Where $CHARGE_{transport,h}$ is the hourly charging of each transport technology (both EVs and ICEs for all four transport categories), $profile_h^{transport}$ is the predefined hourly charging profile of each of the transport technologies and $Q_{transport}$ is the charging capacity of transport technology $transport$.

We consider an average of one charge per week for each transport technology, and since the energy can be stored in the vehicle during the whole one week, the transport demand that should be satisfied is considered to have a weekly adequacy. The hourly demand of transport in vehicle.km should be satisfied from equations (A.5a-d) and the charging profiles should be applied to account for the charging behaviour of different transport technologies from Equation (A.15). We define Equation (A.16) to keep both charging and demand constraints above and to let the vehicles choose the day of charging during the week:

$$\sum_{h \in w} CHARGE_{transport,h} = \sum_{h \in w} G_{transport,h} \quad (A.16)$$

The storage volume of each transport technology accounts for an upper limit for the weekly charge and weekly energy consumption of it. While this storage volume is free of charge for ICE vehicles, electric vehicles' main cost component is this battery storage volume. Therefore, we define the reservoir size (storage volume) for each transport technology (Equation A.17).

$$\sum_{h \in w} CHARGE_{transport,h} \leq RESERVOIR_{transport} \quad (A.17)$$

Where $RESERVOIR_{transport}$ accounts for the reservoir size of each transport technology (kWh_e for electric vehicles and kWh_{th} for ICE vehicles).

A.3.9. Inclusion of heat networks

Heat can be produced by two different technology classes: distributed technologies such as resistive heating technology, and centralized technologies such as central boilers. Decentralized heating technologies use electricity or gas from the network and provide heating for the local demand, therefore no heat network is needed. On the other hand, the centralized technologies produce heat in large quantities and distribute it for the demand in different locations, which require a heat network. Equation (A.18) separates the central heating technologies and define a heat network capacity for the distribution of produced heat.

$$Q_{heat-net} \geq Q_{central} \quad (A.18)$$

Where $Q_{heat-net}$ is the heat network capacity and $Q_{central}$ is the installed capacity of each central heat production technology in kW_{th}.

Equation (17) allows the heat network to have lower capacity than all the central heating technologies combined, depending on the optimal dispatching of each of them. Another equation is needed to restrict the central heating technologies to pass through the heat network (Equation A.19):

$$G_{heat-net,h} = \sum_{central} G_{central,h} \quad (A.19)$$

Where $G_{heat-net,h}$ is the heat generation passed through heat network and $G_{central,h}$ is the heat generation by each central heating technology at hour h .

A.3.10. Operational constraints of conversion technologies

For open-cycle and combined-cycle gas turbines, there are some safety- and maintenance-related breaks. Equations (A.20), (A.21) and (A.22) limit the annual power production for each of these plants to their maximum annual capacity factors:

$$\sum_h G_{ocgt,h} \leq Q_{ocgt} \times cf_{ocgt} \times 8760 \quad (A.20)$$

$$\sum_h G_{ccgt,h} \leq Q_{ccgt} \times cf_{ccgt} \times 8760 \quad (A.21)$$

$$\sum_h G_{ccgt-ccs,h} \leq Q_{ccgt-ccs} \times cf_{ccgt-ccs} \times 8760 \quad (A.22)$$

Where cf_{ocgt} and cf_{ccgt} are the capacity factors of OCGT and CCGT power plants.

A.3.11. Nuclear-power-related constraints

Addition of nuclear power plants to the model brings three main constraint type equations: ramping up and ramping down rates (because we allow these plants to be used in load-following mode [63]) and the annual maximal capacity factor.

Nuclear power plants have limited flexibility, so definitions of hourly ramp-up and ramp-down rates are essential to model them accurately. Equations (A.23) and (A.24) limit the power production of nuclear power plants with these ramping constraints:

$$G_{nuc,h+1} + RSV_{nuc,h+1} \leq G_{nuc,h} + r_{nuc}^{up} \times Q_{nuc} \quad (A.23)$$

$$G_{nuc,h+1} \geq G_{nuc,h}(1 - r_{nuc}^{down}) \quad (A.24)$$

Where $G_{nuc,h+1}$ is the nuclear power production at hour $h + 1$, $G_{nuc,h}$ is the nuclear power production at hour h , $RSV_{nuc,h+1}$ is the reserve capacity provided by nuclear power plants at hour $h + 1$ and r_{nuc}^{up} and r_{nuc}^{down} are the ramp-up and ramp-down rates for nuclear power production.

The nuclear power plants' capacity factor should also be limited by safety and maintenance constraints. Equation (A.25) quantifies this limitation:

$$\sum_h G_{nuc,h} \leq Q_{nuc} \times cf_{nuc} \times 8760 \quad (A.25)$$

Where cf_{nuc} is the maximum annual capacity factor of nuclear power plants.

A.3.12. Storage-related constraints

To prevent optimization leading to a very high quantity of stored energy in the first hour represented and a low quantity in the last hour, we add a constraint to ensure the replacement of the consumed stored energy in every storage option (Equation A.26):

$$SOC_{str,0} = SOC_{str,8759} + (STORAGE_{str,8759} \times \eta_{str}^{in}) - \left(\frac{G_{str,8759}}{\eta_{str}^{out}}\right) \quad (A.26)$$

While Equations (A.8) and (A.26) define the storage mechanism and constraint in terms of power, we also limit the available volume of energy that can be stored by each storage option (Equation A.27):

$$SOC_{str,h} \leq VOLUME_{str} \quad (A.27)$$

Equation (A.28) limits the entry of energy into the storage units to the charging capacity of each storage unit. Similarly, we consider a charging capacity lower than or equal to the discharging capacity (mainly to limit the charging capacity of batteries) which means that the charging capacity cannot exceed the discharging capacity.

$$SOC_{str,h} \leq S_{str} \leq Q_{str} \quad (A.28)$$

A.3.13. Resource availability related constraints

The maximum installed capacity of each technology depends on land-use-related constraints, social acceptance, the maximum available natural resources and other technical constraints; therefore, a constraint on maximum installed capacity is defined in Equation (A.29) where q_{tec}^{max} is this capacity limit:

$$Q_{tec} \leq q_{tec}^{max} \quad (A.29)$$

Renewable gas production technologies are limited due to land-use and agricultural constraints. Equation (A.30) limits the annual renewable gas production from each of two renewable gas production technologies: methanization and pyro-gasification of biomass.

$$\sum_{h=0}^{8759} G_{biogas,h} \leq g_{biogas}^{max} \quad (A.30)$$

Where $G_{biogas,h}$ is the hourly biogas production from each of renewable gas production technologies and g_{biogas}^{max} is the maximal yearly biogas that can be produced from each of renewable gas production technologies, both in energy values.

Methanation consists of the Sabatier reaction of hydrogen produced from electrolysis of water and green CO₂ produced as a by-product of methanization process. Implication of this limit in the overall methane production from methanation process is presented in Equation (A.31):

$$\sum_{h=0}^{8759} CONVERT_{methanation,h} \leq \sum_{h=0}^{8759} G_{methanization,h} \times \gamma_{methanization}^{CO_2} \quad (A.31)$$

Where $CONVERT_{methanation,h}$ accounts for the hourly methane produced from power-to-methane (methanation) process, $G_{methanization,h}$ is the hourly biogas production from methanization process and $\gamma_{methanization}^{CO_2}$ is the relative share of carbon dioxide to biogas produced from methanization process.

The captured carbon dioxide can't be stored infinitely, and geographical and social constraints limit the exploitation of CCS technology. Equation (A.32) limits the captured CO₂ to the available offshore and onshore storage formations:

$$\varphi_{CO_2}^{max} \geq \sum_h G_{ccgt-ccs,h} \times \tau_{ccgt-ccs} \times e_{ccgt} \quad (A.32)$$

Where $\varphi_{CO_2}^{max}$ is the maximal CO₂ storage potential, $G_{ccgt-ccs,h}$ is hourly power production from CCGT power plants equipped with CCS units, $\tau_{ccgt-ccs}$ is the carbon capture rate of post combustion CCS units, and e_{ccgt} is the specific emission of CCGT power plant with fossil gas (considered with no CCS input).

Appendix B. VRE profiles

The wind power hourly capacity factor profiles found in the renewables.ninja website are prepared in four stages:

- a) Raw data selection: using NASA's MERRA-2 data reanalysis with a spatial resolution of 60km×70km provided by [64]
- b) Downscaling the wind speeds to the wind farms: by interpolating the specific geographic coordinates of each wind farm using LOESS regression,
- c) Calculation of hub height wind speed: by extrapolating the wind speed in available altitudes (2, 10 and 50 meters) to the hub height of the wind turbines using the logarithmic profile law,
- d) Power conversion: using the primary data from [65], the power curves are built (with respect to the chosen wind turbine) and smoothed to represent a farm of several geographically dispersed turbines using a Gaussian filter.

The solar power hourly capacity factor profiles in the renewables.ninja website are prepared in three stages:

- a) Raw data calculation and treatment: using NASA's MERRA data with a spatial resolution of 50km×50km. The diffuse irradiance fraction is estimated using the Bayesian statistical analysis introduced by [66] and the global irradiation is calculated for an inclined plane. The temperature is given at 2m altitude by the MERRA data set.
- b) Downscaling of solar radiation to farm level: values are linearly interpolated from grid cells to the given coordinates.
- c) Power conversion model: Power output of a panel is calculated using [67]'s relative PV performance model which gives temperature-dependent panel efficiency curves.

We first extracted the hourly VRE profiles for each of the 95 counties of France from 2000 to 2018. Then considering the near optimal assumption of proportional installation of new plants to the existing plants, we aggregated these 95 counties to one single node. Therefore, while the model is a single node model with no spatial optimization, the spatial distribution of VRE resources has been taken into account by the spatial aggregation.

To prepare hourly capacity factor profiles for offshore wind power, we first identified all the existing offshore projects around France using the "4C offshore" website¹, and using their locations, we extracted the hourly capacity factor profiles of both floating and grounded offshore wind farms. The Siemens SWT 4.0 130 has been chosen as the offshore wind turbine technology because of recent increase in the market share of this model and its high performance. The hub height of this turbine is set to 120 meters.

¹ <https://www.4coffshore.com/>

Appendix C. Demand profiles preparation

C.1. Heat demand profile

The low temperature heat demand profiles for residential and tertiary sector for different usages (heating, hot water and cooking) are prepared using hourly, daily and monthly demand profiles presented in [18]. Hourly profiles for each week-day and weekend-day are expanded using the daily profiles to the whole week, later using the monthly demand profiles we expanded these hourly demand profiles for one week to each month of the year, and with a final normalization process, we kept the annual heat demand for each usage in each of residential tertiary sector equal to the projected demand for 2050 by [3] and [4] scenarios. Mid and high temperature heat demand profiles are industrial heat demand. All the heat demand that is more than 500°C is high temperature, and all between 100°C and 500°C are mid temperature and demand. Because of lack of data, we consider flat profiles for both mid and high temperature heat demand.

According to [20] the population density should be high enough to have heat network viable. According to [68], 60% of the urban areas can be considered dense enough for a cost-effective development of district heating. Considering 87% of urban population share for France (projection for 2050 by Sénat¹), only 52.2% of residential and tertiary sectors' heating can be provided by central heating (we assume that for agriculture and industry it is not possible to use central heating), therefore 13.36Mtoe of heating demand can be provided by central heating at maximum. On the other hand, ADEME predicts a 50% of heating from buildings sector can be satisfied by heat pumps by 2050 [28]. Therefore, we limit the central heating with 13.36Mtoe.

C.2. Transport demand profile

Like the previous section, hourly profiles for each day type (weekday or weekend) as well as a daily profile for a week, and a monthly profile for one year are available in [18] for each passenger and freight transport category. The considered transport modes are light vehicles (particular or utility scale), buses/public transportation and trains as passenger modes and heavy vehicles, utility vehicles and trains as the freight transport modes. We excluded aerial and water transport options because of the lack of data, and the insignificance of these modes in comparison with the other transportation modes. Using the same method presented above, we prepared annual hourly demand profile for each of the transport modes and categorized them in four main categories of light vehicles, heavy vehicles, buses and trains². Using daily, monthly and annual correction factors, we maintained the annual transport demand projected by [3] and [4] in vehicle-kilometres.

C.3. Electricity demand profile

ADEME's central scenario hourly demand profile for 2050 is taken as the electricity demand profile for the model [28]. This demand profile amounts to 423 TWh_e /year, 12% less than the average power consumption in the last 10 years. This takes into account foreseeable change in the demand profile up to 2050, including a reduced demand for lighting and heating and an increased demand for air conditioning and electric vehicles. This demand profile includes heating, cooking, hot water usage and electric vehicle charging demand, therefore they should be subtracted from this demand profile to reach to an only electricity demand. By subtracting the heat and transport demand profiles

¹ <https://www.senat.fr/rap/r10-594-1/r10-594-14.html>

² Because of lack of data and continuity of the public transportation services, we considered a flat hourly demand profile for the transport demand by train.

(normalized again since only a part of these demands is satisfied by electricity), we build an hourly specific electricity demand profile for 2050.

C.4. Hydrogen demand profile

The needed coal for the steel production is estimated to be 3.5Mtoe [3], [4]. We consider the same amount of energy intensity but instead of coal, we consider hydrogen. The annual hydrogen demand is divided by 8760 (number of time-slices in in year) to produce a flat demand profile for hydrogen.

C.5. Industry demand profiles

The energy demand for industry is the same value as ADEME's scenario ([3]), but since no repartition between the usages are provided, we use the heat-electricity usage repartition provided by négaWatt's "scenario négaWatt 2017-2050" [5]. Because of lack of data and high flexibility of industrials' energy demand with respect to the energy price, we consider a flat electricity and heat profile for industry, and we add them to the heat and electricity profiles constructed in previous sections.

Appendix D. Model parametrization

Equations (A.20), (A.21), (A.22), (A.23), (A.24), (A.25) and (A.31) need technology-related input parameters. These parameters such as ramp rate, annual maximal capacity factor (availability limits due to maintenance) and the limiting factors of different processes need to be introduced into the model. Similarly, Equation (A.9), the reserve requirement definition, consists of several input parameters relating the required secondary reserves to installed capacities of VRE technologies and hourly demand profiles. Fossil gas with CCS is not a zero-emission technology and according to European Union's Joint Research Center (JRC), it captures only 86% of the carbon dioxide produced by the combustion, thus leaving residual emissions [32]. The values of these input parameters, as well as their sources are presented in Table D.1.

It is worth to mention that according to Agora energiewende, the ramping rates (both upward and downward) for OCGT and CCGT power plants can go easily 100% in less than an hour [69]. While CCGT power plants show enough flexibility in hourly scales, the addition of carbon capture units to these power plants can decrease their flexibility. Nevertheless, according to [70] the CCGT power plants equipped with CCS units have enough flexibility to reach to ramping rates as high as the full load power in less than one hour. Therefore, we consider full hourly-flexible operations for both OCGT and CCS-equipped CCGT power plants.

Table D.1. Technical parameters of the model

parameter	definition	value	source
cf_{ocgt}	Annual maximal capacity factor of OCGT	90%	[32]
cf_{ccgt}	Annual maximal capacity factor of CCGT	85%	[32]
cf_{nuc}	Annual maximal capacity factor of nuclear plants	90%	[31]
r_{nuc}^{up}	Hourly ramping up rate of nuclear plants	50%	[71]
r_{nuc}^{down}	Hourly ramping down rate of nuclear plants	50%	[71]
$\epsilon_{offshore}$	Additional FRR requirement for offshore wind	0.027	[62]
$\epsilon_{onshore}$	Additional FRR requirement for onshore wind	0.027	[62]
ϵ_{pv}	Additional FRR requirement for solar PV	0.038	[62]
$\delta_{variation}^{load}$	Load variation factor	0.1	[61]
$\delta_{uncertainty}^{load}$	Load uncertainty because of demand forecast error	0.01	[61]
$\tau_{ccgt-ccs}$	The capture rate of CCS	86%	[32]
$\gamma_{methanization}^{CO_2}$	The relative share of CO ₂ to methane in methanization process	3/7	[30]
e_{ccgt}	The specific emission of CCGT power plant with fossil gas	340tCO ₂ /GWh _e	[32]
e_{ocgt}	The specific emission of OCGT power plant with fossil gas	510tCO ₂ /GWh _e	[32]

Equations (A.7), (A.12), (A.13), (A.14), (A.22), (A.23), (A.24), (A.29), (A.30) and (A.32) also have some input parameters with respect to the chosen country. These parameters are the maximal available energy from the constrained technologies, maximum available capacities and hourly and monthly profiles of hydro-electricity and variable renewable energy technologies. In this paper we study the

French energy sector, therefore we use the values provided for France. Table D.2 summarizes these values and their resources.

Table D.2. Country-specific limiting input parameters of model

parameter	definition	value	source
$lake_m^*$	Monthly maximum electricity from dams & reservoirs	See GitHub ¹	RTE (online)
$cf_{vre,h}^{**}$	Hourly power production profiles for VRE technologies (floating and monopole offshore wind power, onshore win power, solar PV and run-of-river)	See GitHub ²	Renewables.ninja & RTE (online)
g_{biogas}^{max}	Annual maximal biogas production from methanization and pyro-gasification	Methanization: 152TWh _{th} Pyro-gasification: 122TWh _{th}	[30]
q_{tec}^{max}	Maximum installable capacity limit for each technology	See GitHub ³	[29]
$profile_h^{transport}$	Hourly charging profiles for each transport category for each engine type (EV or ICE)	See Github ⁴	[18]
$\phi_{CO_2}^{max}$	The maximal available CO ₂ storage capacity for France in 2050	93MtCO ₂ ^{***}	[72] and CCFN ⁵

* This parameter is calculated by summing hourly power production from this hydroelectric energy resource over each month of the year to capture the meteorological variation of hydroelectricity, using the online portal of RTE⁶.

** Hourly run-of-river power production data from the RTE online portal has been used to prepare the hourly capacity factor profile of this energy resource, while other VRE profiles are prepared from renewables.ninja website explained in chapter 2.2.1.

***The average of 4 scenarios presented in [72] leads to 53MtCO₂/year of available onshore storage for France. The French Norwegian collaboration on carbon capture and storage approves 20MtCO₂/year of storage in the North Sea, and a possible extension of the collaboration for a supplementary 20MtCO₂/year.

¹ <https://github.com/BehrangShirizadeh/EOLES/blob/master/inputs/lake2006.csv>

² https://github.com/BehrangShirizadeh/EOLES/blob/master/inputs/vre_profiles2006f.csv

³ https://github.com/BehrangShirizadeh/EOLES/blob/master/inputs/max_capas.csv

⁴ https://github.com/BehrangShirizadeh/EOLES/blob/master/inputs/t_profiles.csv

⁵ <https://www.ccfn.no/actualites/n/news/french-norwegian-collaboration-on-carbon-capture-and-storage.html>

⁶ <https://www.rte-france.com/fr/eco2mix/eco2mix-telechargement>

Appendix E. Acronyms of energy production, conversion and storage technologies

Table E.1. Technology labels and their definitions

Technology label	Explanation	Technology label	Explanation
Offshore	Offshore wind power (both floating and grounded)	G2P	Gas-to-power options (OCGT, CCGT and CCGT-CCS)
Onshore	Onshore wind power	G2H	Gas-to-heat options (centralized and decentralized boilers)
PV	Solar PV (ground and utility and residential rooftop)	G2ICE	Gas for transport by ICEs
Hydro	Hydro-electricity (both run-of-river and lake generated)	Resistive	Electrical heating by resistive heaters
Nuclear	New nuclear power (EPR)	Hpc	Centralized electrical heat pumps
OCGT	Open-cycle gas turbine	Hpd	Decentralized (individual) electrical heat pumps
CCGT	Combined-cycle gas turbine	Boilerc	Centralized gas boilers
CCGT-CCS	Combined-cycle gas turbine with post-combustion CCS	Boilerd	Decentralized (individual) gas boilers
P2G	Power-to-gas options	EV_train	Electric trains
P2H	Power-to-heat options	EV_light	Electric vehicles for light individual transport
P2EV	Power for transport by EVs	EV_bus	Electric buses
Ngas	Natural (fossil) gas	EV_heavy	Electric heavy transport vehicles
Methanization	Renewable gas from anaerobic digestion	ICE_light	Light transport vehicles with internal combustion engines
Pyrogaseification	Renewable gas from pyro-gasification of biomass	ICE_bus	Buses with internal combustion engines
P2CH4	Methanaton (electrolysis of water and Sabatier reaction with green CO ₂)	ICE_heavy	Heavy transport vehicles with internal combustion engines
P2H2	Power-to-hydrogen (electrolysis of water)		

Appendix F. The main results for the central availability scenario

Table F.1 shows the installed capacity of each energy production, storage and vector change technology. It is worth to mention that the values for transport technologies reflect the energy consumption capacity by each transport technology (in GW).

Table F.1. installed capacities of energy production, conversion and storage technologies for different SCC scenarios in GW

SCC (€/tCO ₂)	0	100	200	300	400	500
technology	Installed capacity in GW					
Offshore wind	0	3.52	9.87	10.65	17.71	14.51
Onshore wind	49.88	120	120	120	120	120
Solar PV	79.79	84.30	81.21	84.71	109.75	110.01
Run of river	7.5	7.5	7.5	7.5	7.5	7.5
Lake and reservoir	12.86	12.86	12.86	12.86	12.86	12.86
Nuclear	0	3.43	9.00	7.56	1.22	0
Fossil gas	-	-	-	-	-	-
Methanization	0	0	17.35	17.35	17.35	17.35
Pyro-gasification	0	0	0	0	3.57	8.79
OCGT	0	0	0	0	0	0
CCGT	12.08	0	0	0	0	0
CCGT with CCS	0	0	0.30	4.58	12	15.98
Power-to-hydrogen	10.97	15.7	13.71	14.06	16.43	15.77
Power-to-methane	0	0	0	0.76	6.65	6.68
Heat network	8.91	28.22	60.04	56.78	51.52	51.22
Central HP	8.89	28.22	18.03	20.13	24.51	24.7
Individual HP	0	9.68	35.60	36.53	37.72	37.61
Resistive heating	8.97	32.30	38.97	36.33	34.01	32.81
Central boiler	0	0	0	0	0	0
Decentralized boiler	90.24	61.13	8.94	8.94	8.94	8.94
Battery	0	2.51	0.83	1.91	4.73	3.79
PHS	9.30	9.30	9.30	9.30	9.30	9.30
Gas storage	0	0	8.09	13.39	22.13	27.20
CTES	8.91	28.22	60.04	56.78	51.52	51.22
ITES	12.25	30.10	43.50	52.81	64.12	59.36

Table F.2 presents the annual energy production (conversion) by each energy production, storage and vector change technology. It is worth to mention that the values for transport technologies reflect the consumed energy by each transport technology (in TWh).

Table F.2. Annual energy production of each energy production, conversion and storage technology for different SCC scenarios in TWh

SCC (€/tCO ₂)	0	100	200	300	400	500
technology	Annual energy production in TWh					
Offshore wind	0	16.18	45.44	49.00	81.49	66.80
Onshore wind	141.88	341.34	341.34	341.34	341.34	341.34
Solar PV	113.46	119.87	115.48	120.46	156.06	156.44
Run of river	28.48	28.48	28.48	28.48	28.48	28.48
Lake and reservoir	15.30	15.30	15.30	15.30	15.30	15.30
Nuclear	0	26.69	66.93	57.00	9.40	0
Fossil gas	808.49	301.68	0	0	0	0
Methanization	0	0	152	152	152	152
Pyro-gasification	0	0	0	0	31.30	77
OCGT	0	0	0	0	0	0

<i>CCGT</i>	76.54	0	0	0	0	0
<i>CCGT with CCS</i>	0	0	0.41	12.78	54.77	80.04
<i>Power-to-hydrogen</i>	40.51	40.76	40.71	40.69	40.77	40.74
<i>Power-to-methane</i>	0	0	0	3.85	40.22	41.38
<i>Central HP</i>	72.43	129.85	69.16	79.72	102.68	105.36
<i>Individual HP</i>	0	74.92	277.04	269.58	244.59	241.99
<i>Resistive heating</i>	6.34	73.16	87.76	83.19	80.34	80.09
<i>Central boiler</i>	0	0	0	0	0	0
<i>Decentralized boiler</i>	378.94	187.37	51.45	49.79	48.63	47.81
<i>Light EV</i>	4.18	46.61	46.48	46.92	47	47
<i>Heavy EV</i>	0	0	0	5.50	9.64	9.69
<i>Electric bus</i>	0	0	0	1.06	1.10	1.05
<i>Train (electric)</i>	30	30	30	30	30	30
<i>Light ICE</i>	173.91	1.62	2.11	0.34	0	0
<i>Heavy ICE</i>	82.51	82.51	82.51	69.09	59.00	58.87
<i>ICE bus</i>	9.37	9.37	9.37	6.78	6.67	6.81
<i>Battery</i>	0	0.151	0	0	0	0
<i>PHS</i>	15.74	19.23	18.34	19.11	19.77	18.40
<i>Gas storage</i>	0	0	7.14	19.71	45.75	54.98
<i>CTES</i>	0.23	21.34	82.03	71.47	48.51	45.83
<i>ITES</i>	3.63	7.14	5.99	9.46	24.31	23.16

The main economic and emission related outputs of this study for different SCC values are presented in Table F.3.

Table F.3. Main economic and emission related outputs

SCC (€/tCO₂)	0	100	200	300	400	500
<i>Cost with SCC (b€/an)</i>	55.57	68.92	71.82	71.71	70.99	68.68
<i>Technical cost (b€/an)</i>	55.57	62.00	71.84	72.83	77.39	80.37
<i>CO₂ emission (MtCO₂/an)</i>	185.55	69.24	-0.12	-3.73	-15.99	-23.37
<i>CO₂ captured (MtCO₂/an)</i>	0	0	0.12	3.73	15.99	23.37
<i>Electricity LCOE (€/MWh_e)</i>	43.27	41.98	43.35	44.06	43.55	43.79
<i>Gas LCOE (€/MWh_{th})</i>	24.31	43.6	49.47	50.45	59.35	63.22
<i>Heat LCOE (€/MWh_{th})</i>	8.6	24.03	33.58	34.94	36.77	37.06

Appendix G. The CO₂ emissions for no social cost of carbon and the emissions from the actual French energy system

In section 3.3 we showed the CO₂ emissions for different SCC values. In the absence of a SCC, the CO₂ emissions of the energy sector are relatively low in comparison with current emissions of the energy sector (186MtCO₂/year vs. 450MtCO₂/year). This low emission in the absence of a SCC value can be explained considering several factors: First, the existing energy system in France does not rely on an optimal allocation of installed capacities of energy production technologies. This study is a greenfield optimization, which does not consider the existing energy system, but it allocates an absolute optimal case regarding the taken hypothesis for a given year. While most of the existing power plants will be decommissioned by 2050, the hydro-electric power plants will remain, that's why we fixed a minimum installed capacity of these power plants to the existing capacities. On the other hand, in case of retrofitting the nuclear power plants by 20 years, the last historic nuclear power plants in France will be decommissioned between 2050 and 2060 [62]. On the other hand, the Flamanville 3 nuclear reactor which is not commissioned yet will also be in the energy supply that is not considered in this optimization. Moreover, the lifetime of buildings, factories and the infrastructures are not taken into account. Therefore, a greenfield optimization does not reflect the existing energy system precisely. The existing energy system is highly dependent on fossil fuels especially in industry and transport sectors.

Second, the demand projections for 2050 for France are based on several energy consumption reduction assumptions in residential, tertiary and transport sectors. The final energy demand for residential and tertiary sectors for year 2015 were 490TWh and 295TWh respectively, while in the future final energy demand projections, these values are considered to be 293TWh and 168TWh respectively [4]. The high reduction in the final energy demand for each sector is thanks to increased efficiency of electronic appliances, increased isolation of buildings and replacement of light bulbs with LEDs. The final energy demand for the transport sector was 509TWh for 2015 and it is projected to be less than 200TWh in 2050 [4]. ADEME projects a final energy demand reduction from 149Mtoe to 82Mtoe from 2010 to 2050 [3]. Moreover, all the existing scenarios for future French energy mix (négaWatt [5], ADEME [3] and SNBC [4]) project a much lower energy loss from the primary energy production to final energy consumption. According to [4], a primary energy consumption of 250Mtoe for France for the year 2015 satisfies the 142Mtoe of final energy demand at this year. Therefore, although a higher final energy demand is not studied in this paper, one can easily predict the impact of increasing the energy demand for low SCC values; the emissions will be much higher because of increased usage of cheap fossil gas, and since the renewable gas production is limited by land-use and technical constraints, a carbon neutral energy system may need a higher social cost of carbon than only €200/tCO₂.

Appendix H. Energy mix for different availability scenarios

Figure H.1 shows the primary energy mix of each end-use for different availability and the final energy consumption. In case of unavailability of nuclear power, the energy mix becomes fully renewable from the SCC value of €200/tCO₂ on, with no change in emission or cost of the energy system. In fact, since nuclear energy has a very small role in the energy mix, its exclusion does not impact visibly the energy system. The missing energy from nuclear power is supplied partially by offshore wind power and partially by solar power with no change in other energy sources.

Without VRE technologies, the primary energy contains 53% of nuclear energy for an SCC of €100/tCO₂, and the share of nuclear electricity in the primary energy supply can go up to 72%. While in all the availability scenarios, the fossil gas is phased out for €200/tCO₂ of SCC, in case of absence of renewable gas, fossil gas remains an important part of primary energy even for the SCC of €500/tCO₂.

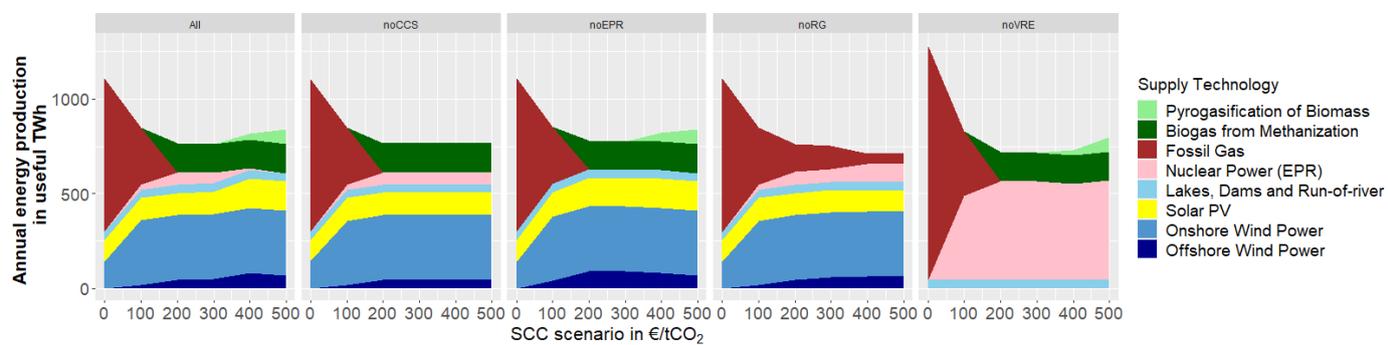


Figure H.1. Primary energy mix for each technology availability scenario for different SCC values