Low-carbon options for the French power sector: What role for renewables, nuclear energy and carbon capture and storage?

Behrang Shirizadeh, Philippe Quirion

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Abstract

In the wake of the Paris agreement, France has set a target of zero net greenhouse gas emissions by 2050. This target can only be achieved by rapidly decreasing the proportion of fossil fuels and accelerating the deployment of low-carbon technologies. We develop a detailed model of the power sector to investigate the role of different low- and negative-emission technologies in the French electricity mix and we identify the impact of the relative cost of these technologies for various values of the social cost of carbon (SCC).

We show that for a wide range of SCC values (from 0 to €500/tCO_2), the optimal power mix consists of roughly 75% of renewable power. For a SCC value of €100/tCO_2, the power sector becomes nearly carbon neutral while for €200/tCO_2 and more it provides negative emissions. The availability of negative emission technologies can decrease the system cost by up to 18% and can create up to 20MtCO_2/year of negative emissions, while the availability of new nuclear power stations is much less important. This study demonstrates the importance of an effective SCC value (as a tax for positive emissions and remuneration for negative emissions) in reaching carbon neutrality at moderate cost. Negative emissions may represent an important carbon market which could attract investments if supported by public policies.

Keywords: Power system modeling; Variable renewables; Negative emissions; Social cost of carbon; Nuclear energy.

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1. Introduction

The 2015 Paris agreement aims to keep the global average temperature increase well below 2°C and reach a net balance between anthropogenic emissions and removals (by sinks) of greenhouse gases (GHG) by the second half of this century (UNFCCC 2015). The literature particularly highlights decarbonization of the power sector, since this is easier to achieve than decarbonizing industry, transport and agriculture (Edenhofer et al 2015). To achieve the goal of keeping global average temperature increases below 2°C, CO_2 emissions from the power sector must fall to, or even below, zero (Sanchez et al. 2016, Rogelj et al. 2015).

Several studies have shown that nuclear power, variable renewable energy (VRE) sources and carbon capture and storage (CCS) technologies are useful CO_2 mitigation options (Brouwer et al. 2016), and according to Rogelj et al. (2018), renewable energy sources (RES) will be the cornerstone of decarbonization, making, with CO_2 capture and storage, a greater contribution than nuclear energy and fossil fuels. Similarly, according to Waisman et al (2019), a drastic increase in the proportion of renewable energy in the electricity mix (from 70% to 85% of the electricity mix) is necessary for the power generation sector, not only from the cost-effectiveness point of view, but also considering the societal and political feasibility. Exclusion of nuclear power has gained high attention in the recent literature because of high uncertainty on its construction time and its negative learning-by-doing rate in the latest projects such as Hinkley Point C in UK, Flamanville 3 in France and Olkiluoto 3 in Finland. Most of this literature highlights the importance of electricity storage and dispatchable renewable energy resources (such as bio-energies) for fully renewable systems (Zerrahn et al, 2015, Shirizadeh et al, 2019). Linares et al (2013), in a Spanish case study, showed that the cost-competitiveness of nuclear power is highly questionable and for a liberalized market, and a public support will be inevitable for investments for new nuclear power plants. Similarly, Kan et al (2020) studied the cost of a future low-carbon Swedish power system and they concluded that once the old nuclear power plants are decommissioned (by 2040), there is no economic interest in the new nuclear power plants.

The official target presented by the French government in its energy-climate law is to reach zero net GHG emissions by 2050 (MTES, 2019). While the French electricity sector is relatively decarbonized, the relative proportions of renewable energy resources and nuclear power is a highly debated topic. With 63GW of installed capacity by the end of 2019, nuclear power dominates the French electricity mix, accounting for 70.6% of net electricity production in 2018 (CGDD, 2019). France is at the crossroads of

the decision to retrofit existing power plants and invest in new nuclear power plants, or slowly decrease the proportion of nuclear power in favor of a renewables-dominated power mix (DNTE, 2013).

In France, a wide range of prospective studies have been conducted by public authorities, companies and associations. Among the scenarios proposed by associations and public authorities, we can highlight "100% renewable electricity mix" (ADEME, 2015) and "Electricity mix development trajectories for 2020-2060" (ADEME, 2018a) by ADEME (French environment and energy management agency), "negaWatt scenario 2017-2050" (RTE 2017), "French national low carbon strategy" (SNBC, 2019) and "Projected adequacy report" by RTE (French transmission network operator) presenting four electricity mix scenarios for France (RTE, 2019).

Similarly, a very wide range of academic studies evaluate the optimal electricity mix for France by 2050. Krakowski et al. (2016) argue that increasing the proportion of RES from 40% to 100% would lead to a power system that would be twice as expensive (more than €60bn/year vs. €30bn/year), and similarly Villavicencio (2017) shows an even higher cost for a 100% RES power system (€180bn/year). The costs from the last two studies are equivalent to three times and nine times the current electricity price in France respectively. On the other hand, both ADEME reports (ADEME, 2015 and ADEME, 2018) show that investing in new nuclear power plants is not an optimal choice and that in an optimal scenario, renewables will represent 85% and 95% of the electricity mix in 2050 and 2060 respectively. This very high level of renewable electricity is expected to cost less than the current electricity price (€90/MWh vs. €100/MWh excluding taxes).

The controversial findings in the existing literature for France raise the question of the impact of cost scenarios for the respective proportion of nuclear power and VRE technologies in the optimal power mix. Moreover, carbon capture and storage (CCS) and negative emission technologies such as bioenergy with carbon capture and storage (BECCS) are not included in any of the existing literature for France, while these technologies show promising potential for decarbonizing the electricity sector. The special 1.5°C global warming report published by the Intergovernmental Panel on Climate Change (IPCC, 2018) argues that "Significant near-term emissions reductions and measures to lower energy and land demand" is necessary to limit the carbon dioxide removal (CDR) technologies to a few hundred $GtCO_2$ without reliance on BECCS. Daggash et al. (2019) conclude that it is significantly cheaper (37% to 48%) to decarbonize the power sector using BECCS and DACCS than to consider only VRE technologies with storage options.

This paper aims to evaluate the relative role of renewable energy technologies, nuclear power and carbon capture and storage technologies, the impact of different cost scenarios in the optimal electricity mix and the integration of the social cost of carbon (SCC) into these evaluations. To investigate these issues, we develop the EOLES_elec model, from the EOLES (Energy Optimization for Low Emission Systems) family of models, which considers only the power sector. The EOLES family of models simultaneously optimizes the dispatch (assuring an hourly supply-demand balance) and the investment in production and storage capacities, in order to minimize the total cost. The paper examines the sensitivity of the optimal power mix to a wide range of SCC scenarios (from 0 to €500/tCO_2) and to the future cost development of new nuclear power plants (from €3,000/kW to €4,500/kW of capital expenditure) and VREs (three main scenarios; low, central and high cost for wind and solar power).

The remainder of this paper is organized as follows. Section 2 presents the methods: the EOLES_elec model with respect to its previous version and the input parameters used. The results and discussion are presented in sections 3 and 4 while section 5 concludes the article.

2. Methods

2.1. EOLES_elec model

The EOLES family of models optimizes the investment and operation of an energy system in order to minimize the total cost while satisfying energy demand. EOLES_elec is the electricity version of this family of models. It minimizes the annualized power generation and storage costs, including the cost of connection to the grid. It includes eight power generation technologies: offshore and onshore wind power, solar photovoltaics (PV), run-of-river and lake-generated hydro-electricity, nuclear power (EPR, i.e. third generation European pressurized water reactors), open-cycle gas turbines and combined-cycle gas turbines equipped with post-combustion carbon capture and storage[c]. The latter two generation technologies burn methane which can come from three sources: fossil natural gas, biogas from anaerobic digestion and renewable gas from power-to-gas technology (methanation)[d]. EOLES_elec also

[c] The capture rate of post-combustion carbon capture is 86%, which would lead to high residual emissions from natural gas. Oxy-fuel combustion with carbon capture and storage has a higher capture rate (nearly 100% for natural gas). However, because of the lack of information about its cost, we did not include this technology in the model.

[d] We chose the main representative technologies for three main storage types; short-term, mid-term and long-term storage options. Hydrogen as direct injection to gas network or separate storage in salt caverns could be two other power-to-gas storage options. An alternative scenario with both types of hydrogen is presented in Appendix 8. Since we observed no visible change by excluding these two power-to-hydrogen options from the preset technologies in the model, and it increased the computation time of the model, we considered methanation as the only power-to-gas technology.

includes four energy storage technologies: pumped-hydro storage (PHS), Li-Ion batteries and two types of methanation. These technologies are shown in Figure 1.

The main simplification assumptions in the EOLES_elec model are as follows; it considers continental France as a single node, demand is inelastic, and the optimization is based on full information about the weather and electricity demand. This model uses only linear optimization[e]: non-linear constraints might improve accuracy, especially when studying unit commitment, however they entail a large increase in computation time. Palmintier (2014) has shown that linear programming provides an interesting trade-off, with little impact on cost, CO_2 emissions and investment estimations, but speeds up processing by up to 1,500 times. Similarly, according to Cebulla et al (2017), in modelling thermal power plants, mixed-integer linear programming can capture the techno-economic characteristics more precisely compared to linear programming (LP), while LP has a superior computational performance. Linear programming merit order dispatch underestimates the storage demand compared to mixed-integer linear programming (MILP)[f], but this divergence is less visible for high renewable share in power system. The model is written in GAMS and solved using the CPLEX solver. The code and data are available on Github.[g]

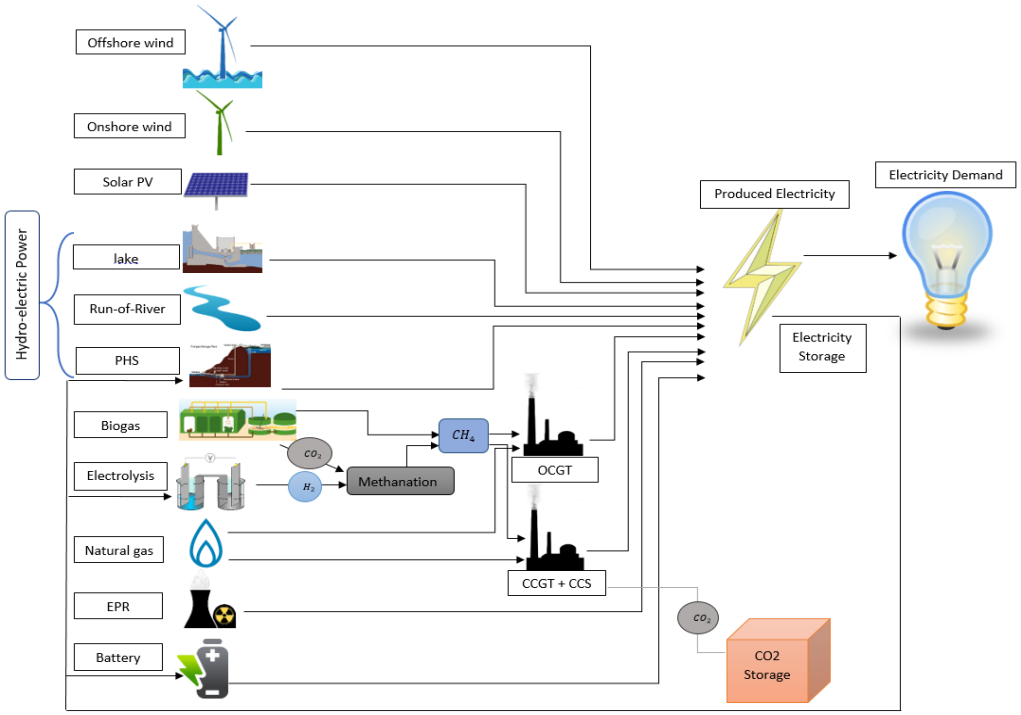

Figure 1. Graphical description of the EOLES_elec model

[e] It can be considered as simplified linear programming for merit order dispatch.
[f] It can be considered as mixed-integer unit-commitment with economic dispatch.
[g] https://github.com/BehrangShirizadeh/EOLES_elec

2.1.1. Objective function

The objective function, shown in Equation (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, two CAPEX-related costs are accounted for: one proportional to the charging capacity in €/kW_e ($capex_{str}^{ch}$), the second proportional to the energy capacity in €/kWh_e($annuity_{str}^{en}$).

$$COST = \left(\sum_{tec}[(Q_{tec} - q_{tec}^{ex}) \times annuity_{tec}] + \sum_{str}(VOLUME_{str} \times annuity_{str}^{en}) + \sum_{tec}(Q_{tec} \times fO\&M_{tec}) + \sum_{str}(S_{str} \times \left(capex_{str}^{ch} + fO\&M_{str}^{ch}\right)) + \sum_{tec}\sum_{h}(G_{tec,h} \times (vO\&M_{tec} + e_{tec}SCC_{CO_2}))\right)/1000 \quad (1)$$

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, $capex_{str}^{ch}$ is the charging annualized investment cost and $fO\&M_{str}^{ch}$ is the charging fixed operation and maintenance cost of the storage technology str, 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 €/tCO_2.

2.1.2. Adequacy equation

Electricity demand must be met for each hour. If power production exceeds electricity demand, the excess electricity can be either sent to storage units or curtailed (equation 3).

$$\sum_{tec} G_{tec,h} \geq demand_h + \sum_{str} STORAGE_{str,h} \quad (3)$$

Where $G_{tec,h}$ is the power produced by technology *tec* at hour *h* and $STORAGE_{str,h}$ is the energy entering storage technology *str* at hour *h.*

2.1.3. 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 4).

$$G_{vre,h} = Q_{vre} \times cf_{vre,h} \quad (4)$$

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

2.1.4. 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 5):

$$STORED_{str,h+1} = STORED_{str,h} + (STORAGE_{str,h} \times \eta_{str}^{in}) - (\frac{G_{str,h}}{\eta_{str}^{out}}) \quad (5)$$

Where $STORED_{str,h}$ is the energy in 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.

2.1.5. Secondary reserve requirements

Three types of operating reserves are defined by ENTSO-E (2013), depending on their activation speed. 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 startup-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 (6). 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:

$$\sum_{frr} RSV_{frr,h} = \sum_{vre}(\varepsilon_{vre} \times Q_{vre}) + demand_h \times (1 + \delta_{variation}^{load}) \times \delta_{uncertainty}^{load} \quad (6)$$

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 Van Stiphout et al. (2017).

2.1.6. Power-production-related constraints

The relationship between hourly-generated electricity and installed capacity can be calculated using equation (7). 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.

$$G_{tec,h} \leq Q_{tec} \quad (7)$$

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 (8).

$$Q_{frr} \geq G_{frr,h} + RSV_{frr,h} \quad (8)$$

Monthly available energy for the hydroelectricity generated by lakes and reservoirs is defined using monthly lake inflows (equation 9). 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 Perrier (2018).

$$lake_m \geq \sum_{h \in m} G_{lake,h} \quad (9)$$

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.

Run-of-river power plants represent another source of hydro-electric power. River flow is also strongly dependent on meteorological conditions and it can be considered as a variable renewable energy resource. We define the hourly capacity factor profile of this energy resource as $river_h$ in equation (10):

$$G_{river,h} = Q_{river} \times river_h \quad (10)$$

As shown in Figure 1, in addition to natural gas, two renewable gas technologies are considered: biogas and methanation. They can be sent either to OCGT power plants with high operational flexibility, with no emissions for renewable gas, or to CCGT power plants equipped with post-combustion CCS where renewable gas technologies have negative emissions and natural gas has residual positive emissions.

Equations (11) and (12) show the operation of these two power plants with each of three gas production technologies:

$$G_{ocgt,h} = G_{biogas1,h} + G_{methanation1,h} + G_{ngas1,h} \qquad (11)$$

Where $G_{biogas1,h}$ and $G_{methanation1,h}$ are the power production from each of two combustible renewable gas resources by OCGT, $G_{ngas1,h}$ is the power production from natural gas in OCGT, and $G_{ocgt,h}$ is the power production from the OCGT power plant which uses these three resources as fuel. The efficiency of this combustion process is taken into account for power production from biogas, natural gas and the discharge efficiency of the methanation process, so capacities and production are expressed in electrical MW (MW_e) and TWh (TWh_e).

$$G_{ccgt-ccs,h} = G_{biogas2,h} + G_{methanation2,h} + G_{ngas2,h} \quad (12)$$

Where $G_{biogas2,h}$ and $G_{methanation2,h}$ are the power production from each of two combustible renewable gas resources, $G_{ngas2,h}$ is the power production from natural gas and $G_{ccgt-ccs,h}$ is the power production from the CCGT power plant combined with post-combustion CCS which uses these three fuels.

The OCGT power plants are chosen because of their high ramping rates, and consequently their higher load-following capability. Since in the study used for cost assumptions (JRC 2017) the only post-combustion CCS technology for gas power plants was the combination of CCGT and CCS, CCGT power plants are considered to be gas plants equipped with post-combustion CCS technology.

Equation (13) limits the annual power production from biogas (with and without CCS), where e_{biogas}^{max} is the maximal annual power that can be produced from biogas:

$$\sum_{h=0}^{8759} G_{biogas1,h} + \sum_{h=0}^{8759} G_{biogas2,h} \leq e_{biogas}^{max} \quad (13)$$

For open-cycle and combined-cycle gas turbines, there are some safety- and maintenance-related breaks. Equations (14) and (15) limit the annual power production for each of these plants to their maximum annual capacity factors:

$$\sum_h G_{ocgt,h} \leq Q_{ocgt} \times cf_{ocgt} \times 8760 \quad (14)$$

$$\sum_h G_{ccgt-ccs,h} \leq Q_{ccgt-ccs} \times cf_{ccgt} \times 8760 \quad (15)$$

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

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 technological constraint on maximum installed capacity is defined in equation (16) where q_{tec}^{max} is this capacity limit:

$$Q_{tec} \leq q_{tec}^{max} \quad (16)$$

2.1.7. 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, Loisel et al., 2018) 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 (17) and (18) limit the power production of nuclear power plants with these ramping constraints:

$$G_{nuc,h+1} + RSV_{nuc,h+1} \leq G_{nuc,h} + r_{nuc}^{up} \times Q_{nuc} \quad (17)$$

$$G_{nuc,h+1} \geq G_{nuc,h}(1 - r_{nuc}^{down}) \quad (18)$$

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 (19) quantifies this limitation:

$$\sum_h G_{nuc,h} \leq Q_{nuc} \times cf_{nuc} \times 8760 \quad (19)$$

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

2.1.8. 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 ***cyclicity*** constraint to ensure the replacement of the consumed stored electricity in every storage option (equation 20):

$$STORED_{str,0} = STORED_{str,8759} + (STORAGE_{str,8759} \times \eta_{str}^{in}) - (\frac{G_{str,8759}}{\eta_{str}^{out}}) \quad (20)$$

While equations (5) and (20) 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 21):

$$STORED_{str,h} \leq VOLUME_{str} \qquad (21)$$

Equation (22) 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.

$$STORED_{str,h} \leq S_{str} \leq Q_{str} \qquad (22)$$

Methanation is constrained by available green CO_2. In EOLES_elec, we only consider the CO_2 as a byproduct of anaerobic digestion, therefore methanation is limited by the available biogas from anaerobic digestion. Equation (23) applies this constraint;

$$\sum_h G_{methanation1,h}/\eta^{OCGT} + \sum_h G_{methanation2,h}/\eta^{CCGT-CCS} \leq \gamma^{CO_2}_{methanation} \times e^{max}_{total,biogas} \qquad (23)$$

Where $G_{methanation1,h}$ and $G_{methanation2,h}$ are hourlypower production from methanation without and with carbon capture and storage respectively and η^{OCGT} and $\eta^{CCGT-CCS}$ are the efficiencies of OCGT and CCGT with CCS power plants , $\gamma^{CO_2}_{methanation}$ is the molar ratio of CO_2 to CH_4 in the methanization process, and $e^{max}_{total,biogas}$ is the total annual biogas production from methanization.

2.2. Input parameters

2.2.1. VRE profiles

Variable renewable energies' (offshore and onshore wind and solar PV) hourly capacity factors have been prepared using the renewables.ninja website[h], which provides the hourly capacity factor profiles of solar and wind power from 2000 to 2018, following the methods elaborated by Pfenninger and Staffell (2016) and Staffell and Pfenninger (2016). These profiles are calculated for every county (*département*) of continental France. The spatial distribution for onshore wind and PV is based on the observed distribution in 2017.

These renewables.ninja factors reconstructed from weather data provide a good approximation of observed data: Moraes et al. (2018) finds a correlation of 0.98 for wind and 0.97 for solar power with

[h] https://www.renewables.ninja/

the observed annual duration curves (in which the capacity factors are ranked in descending order of magnitude) provided by the French transmission system operator (RTE).

To prepare hourly capacity factor profiles for offshore wind power, we first identified all the existing offshore projects around France using the "4C offshore" website[i], 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.

Appendix 1 provides more information about the methodology used in the preparation of hourly capacity factor profiles of wind and solar power resources.

2.2.2. Electricity demand profile

Hourly electricity demand is ADEME's (2015) central demand scenario for 2050. This demand profile falls in the middle of the four proposed demand scenarios for 2050 in France by NEA et al. (2013) during the national debates on the French energy transition (DNTE). It amounts to 422 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. In this demand scenario, almost half of the vehicles are electric or plug-in hybrids (10.7 million out of 22).

2.2.3. Limiting capacity and power production constraints

Similar to the 100% version of the EOLES model, we use the maximal capacities of VRE technologies from ADEME (2018), the maximal and existing hydro-electricity capacities from ADEME (2015), and the run-of-river and lake-generated hydro-electricity profiles from RTE's (the French transmission network operator) online portal for year 2016[j].

2.2.4. Economic parameters

Table 1 summarizes the economic parameters (and their sources) used as input data in EOLES model.

[i] https://www.4coffshore.com/
[j] https://www.rte-france.com/fr/eco2mix/eco2mix-telechargement

Table 1. Economic parameters of power production technologies

Technology	**Overnight costs (€/kW$_e$)**	**Lifetime (years)**	**Annuity (€/kW$_e$/year)**	**Fixed O&M (€/kW$_e$/year)**	**Variable O&M (€/MWh$_e$)**	**Construction time (years)**	**Efficiency (%)**	**LCOE estimate$^+$ (€/MWh$_e$)**	**Source**
*Offshore wind farm**	2,330	30	150.9	47	0	1	-	43	JRC (2017)
*Onshore wind farm**	1,130	25	81.2	34.5	0	1	-	40	JRC (2017)
*Solar PV**	423	25	30.7	9.2	0	0.5	-	28	JRC (2017)
Hydroelectricity – lake and reservoir	2,275	60	115.2	11.4	0	1	-	102	JRC (2017)
Hydroelectricity – run-of-river	2,970	60	150.4	14.9	0	1	-	42	JRC (2017)
Biogas (Anaerobic digestion)	2,510	25	141.6	83.9	3.1	1	-	84/103**	JRC (2017)
Natural gas	-	-	-	-	50/61***	-	-	50/61***	IEA (2018)
Nuclear power	3,750	60	262.6	97.5	9.5****	10	38%	65	JRC (2014)
CCGT with CCS	1,280	30	82.1	32	18*****	1	55%	41	JRC (2017)
OCGT	550	30	35.3	16.5	-	1	45%	39	JRC (2014)

$^+$The LCOE of each technology is an output of the model since the capacity factor of each non-vre technology is chosen endogenously in the EOLES_elec model. But to have an initial idea about the unit cost of electricity, we used estimated capacity factors of 80% for nuclear power, 15% for the OCGT and 60% for CCGT power plants.

*For offshore wind power on monopiles at 30km to 60km from the shore, for onshore wind power, turbines with medium specific capacity (0.3kW/m^2) 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.

**€84/MWh-e for CCGT power plants with 55% efficiency, and €103/MWh for OCGT power plants with 45% efficiency.

***€50/MWh-e for CCGT power plants with 55% efficiency, and €61/MWh for OCGT power plants with 45% efficiency (accounting for $9/MBtu, projected for Europe for the year 2040 by the IEA in the World Energy Outlook 2018).

****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.

*****This variable cost accounts for a 500km CO_2 transport pipeline (in €/tCO_2) and offshore storage costs estimated by Rubin et al. (2015).

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 the 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 projects at Olkiluoto in Finland, Hinkley Point C in the UK and Flamanville 3 in France show much longer construction times. According to NEA (2018), an average construction time of 10 years can be considered for new nuclear power plants. The same report provides a labor-during-construction profile: the annual construction expenditure has been calculated assuming expenditure to be proportional to labor each year. Using the formula provided by the GEN IV international forum (2007), the interest during construction can be calculated using equation (24):

$$IDC = \sum_{j=1}^{ct} C_j[(1+r)^{t_{op}-j} - 1] \qquad (24)$$

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=€1,078/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 €5,311/kW, which is the value used to calculate the annuity.

Table 2 shows the economic parameters of power storage technologies.

Table 2. Economic parameters of storage technologies

Technology	Overnight costs (€/kW$_e$)	CAPEX (€/kWh$_e$)	Lifetime (years)	Annuity (€/kW$_e$/ year)	Fixed O&M (€/kW$_e$/year)	Variable O&M (€/MWh$_e$)	Storage annuity (€/kWh$_e$/year)	Construction time (years)	Efficiency (input / output)	Source
Pumped hydro storage (PHS)	500	5	55	25.8050	7.5	0	0.2469	1	95%/90%	FCH-JU (2015)
Battery storage (Li-Ion)	140	100	12.5	15.2225	1.96	0	10.6340	0.5	90%/95%	Schmidt (2019)
Methanation	1150	0	20/25*	87.9481	59.25	5.44	0	1	59%/45%	ENEA (2016)

It is worth mentioning that OCGT and CCGT with CCS power plants are technologies using natural gas, biogas and renewable methane (from power-to-gas) as fuel; therefore, the full cost of electricity generated through these technologies is the sum of the combustion technology cost and the used fuel cost. The cost of CO_2 transportation is presented in Appendix 2.

2.2.5. Model parametrization

Equations (14), (15), (17), (18) and (19) need technology-related input parameters. These parameters such as ramp rate, annual maximal capacity factor (availability limits due to maintenance) and efficiencies of different processes need to be introduced into the model. Similarly, equation (6), the reserve requirement definition, consists of several input parameters relating the required secondary reserves to installed capacities of VRE technologies and hourly demand profiles. Natural gas with CCS is not a zero-emission technology and according to JRC (2014), it captures only 86% of the carbon dioxide produced by the combustion, thus leaving residual emissions. The values of these input parameters, as well as their sources are presented in Table 3.

Table 3. Technical parameters of the model

parameter	definition	value	source
cf_{ocgt}	Annual maximal capacity factor of OCGT	90%	JRC (2014)
cf_{ccgt}	Annual maximal capacity factor of CCGT	85%	JRC (2014)
cf_{nuc}	Annual maximal capacity factor of nuclear plants	90%	JRC (2017)
r_{nuc}^{up}	Hourly ramping up rate of nuclear plants	25%	NEA (2011)
r_{nuc}^{down}	Hourly ramping down rate of nuclear plants	25%	NEA (2011)
$\varepsilon_{offshore}$	Additional FRR requirement for offshore wind	0.027	Perrier (2018)
$\varepsilon_{onshore}$	Additional FRR requirement for onshore wind	0.027	Perrier (2018)
ε_{PV}	Additional FRR requirement for solar PV	0.038	Perrier (2018)
$\delta_{variation}^{load}$	Load variation factor	0.1	Van Stiphout et al (2017)
$\delta_{uncertainty}^{load}$	Load uncertainty because of demand forecast error	0.01	Van Stiphout et al (2017)
$\eta_{ccgt-ccs}$	The capture efficiency of CCS	86%	JRC (2014)
$\gamma_{methanation}^{CO_2}$	The relative share of CO_2 to methane in methanization process	3/7	ADEME (2018b)

$e^{max}_{total,biogas}$	Total biogas from methanization projected for France for 2050	152TWh	ADEMPE (2018b)

Equations (9), (10), (13) and (16) 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 technologies. In this paper we study the French power sector, therefore we use the values provided for France. Table 4 summarizes these values and their resources.

Table 4. Country-specific limiting input parameters of model

parameter	definition	value	source
$lake_m$*	Monthly maximum electricity from dams & reservoirs	See GitHub[k]	RTE (2016)
$river_h$**	Hourly maximal power production from run-of-river	See GitHub[l]	RTE (2016)
e^{max}_{biogas}	Annual maximal power production from Biogas	15TWh	ADEME (2013)
q^{max}_{tec}	Maximum installable capacity limit for each technology	See GitHub[m]	ADEME (2018)

* 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 RTE[n] (the French transmission network operator).

** 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.

2.2.6. Choice of discount rate

The discount rate recommended by the French government for use in public socio-economic analyses is 4.5% (Quinet, 2014). This discount rate is used to calculate the annuity in the objective function, using the following equation:

$$annuity_{tec} = \frac{DR \times CAPEX_{tec}((DR \times ct_{tec})+1)}{1-(1+DR)^{-lt_{tec}}} \quad (25)$$

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 of the technology tec. Appendix 7 provides a sensitivity analysis, varying this rate from 2% to 7%.

[k] https://github.com/BehrangShirizadeh/EOLES_elec/blob/master/lake_inflows.csv
[l] https://github.com/BehrangShirizadeh/EOLES_elec/blob/master/run_of_river.csv
[m] https://github.com/BehrangShirizadeh/EOLES_elec/blob/master/max_capas.csv
[n] https://www.rte-france.com/fr/eco2mix/eco2mix-telechargement

2.3. Studied scenarios

We have previously shown the importance of the choice of the weather year data, and that 2006 is the most representative of the period 2000-2017 (Shirizadeh et al. 2019). Therefore, 2006 has been used as the weather year for the hourly capacity factor profiles of VRE technologies. More information about the choice of the weather year can be found in Appendix 3.

The model has been run for 126 cost scenarios: 6 social cost of carbon scenarios, from 0 to €500/tCO_2 in steps of 100€/tCO_2, 7 nuclear power cost scenarios and 3 VRE cost scenarios. For nuclear power, the central scenario is €3,750/kW, ranging from €3,000/kW to €4,500/kW in steps of 250€/kW. VRE cost scenarios are labeled low cost (offshore wind: €1,747.5/kW, onshore wind: €847.5/kW and solar PV: €318/kW), central cost (offshore wind: €2,330/kW, onshore wind: €1,130/kW and solar PV: €423.3/kW) and high cost (offshore wind: €2,912.5/kW, onshore wind: €1,412.5/kW and solar PV: €530/kW), where the variation from the central cost scenario is 25%.

The choice of central scenarios has been made from the cost resources (Tables 1 and 2), while the 25% variation for VRE resources is taken from the expert elicitation survey by Wiser et al. (2016). The cost variation boundaries for nuclear power plants are based on simulations, where the highest cost scenario for this technology is chosen as the scenario where the optimization for central VRE cost scenario and any SCC scenario leads to zero installed capacity of this technology. To retain symmetry, the same relative variation is applied for the lowest cost scenario for nuclear power. The size of the step (6.66%) is chosen because of the high sensitivity of the optimal mix to the cost variation of this technology. The SCC values are based on the official 'value for climate action' social cost of carbon introduced by Quinet et al. (2019) for France for 2050, (between €600/tCO_2 and €900/tCO_2), but the results presented are for a maximum €500/tCO_2 SCC, since no particular change has been observed for higher values.

3. Results

3.1. Central cost scenario

3.1.1. Power mix

Figure 2 shows the annual power production of each technology for central VRE and nuclear power cost scenarios. Whatever the SCC scenario, approximately 75% of the electricity is generated by renewable energy resources. The remaining 25% is shared between nuclear power and natural gas, with or without carbon capture and storage technologies. For low SCC scenarios, nuclear power accounts for only 10% of

annual electricity production, while for high social cost of carbon, the whole remaining 25% is produced by nuclear power.

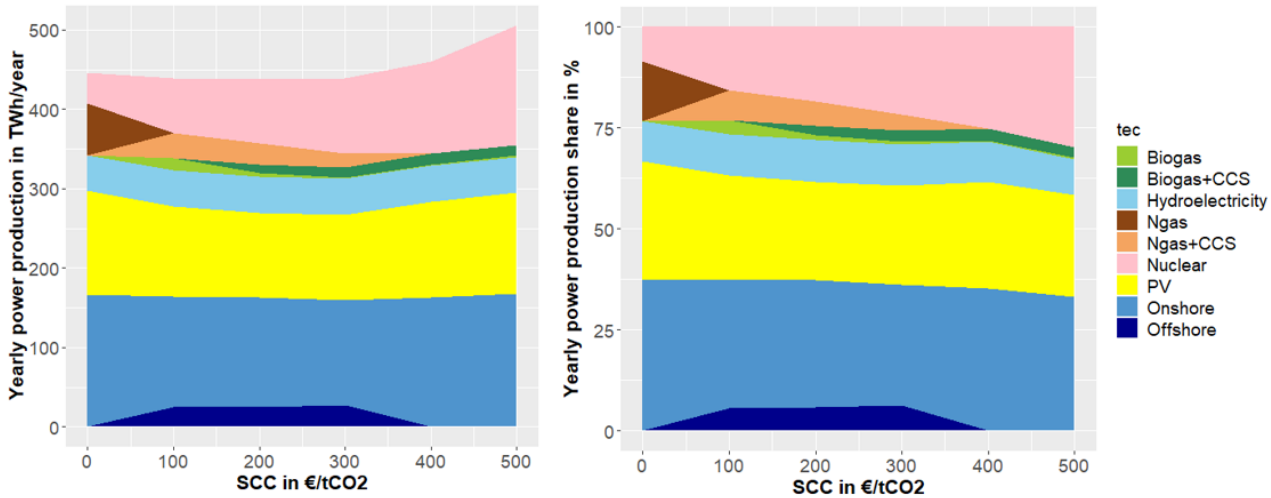

Figure 2. Optimal power mix for central VRE and nuclear power cost scenarios with respect to different SCC scenarios for the studied time horizon (2050)

Figure 3 shows the annual power production from storage options for each social cost of carbon scenario. As we saw from Figure 2, natural gas without CCS exists only for the zero SCC scenario, and once the social cost of carbon is €100/tCO_2 or more, natural gas without CCS is abandoned and replaced by natural gas with CCS and by bio-energies. Because of residual emissions, for high SCCs (€400/tCO_2 and more), natural gas with CCS is also eliminated. We observe from Figure 3 that natural gas with CCS is also abandoned and replaced by the supply chain decarbonized electricity-methanation-CCGT with CCS from a social cost of carbon of €400/tCO_2 upwards.

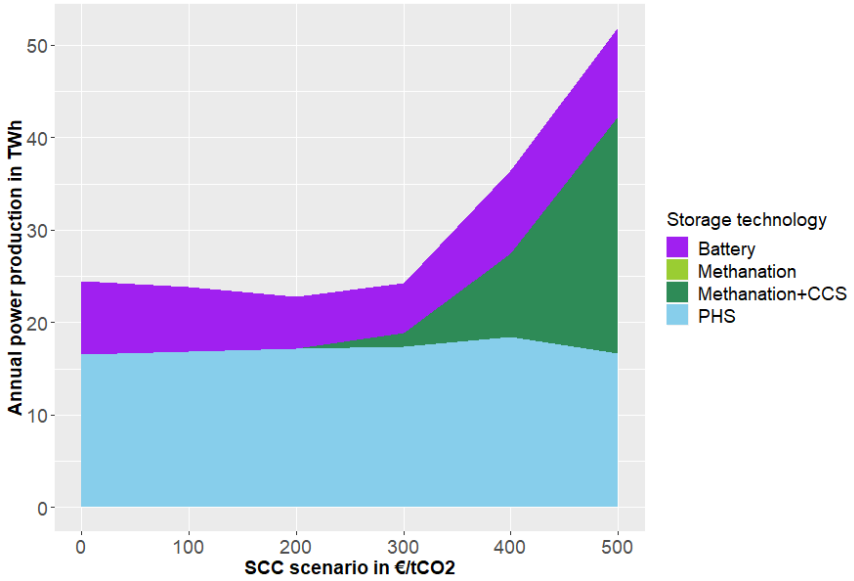

Figure 3. Annual power production by storage technology for the central VRE and nuclear power cost scenario for the considered time horizon (2050)

The installed capacities of each technology and a summary of the main model outputs (such as overall cost and load curtailment) for different SCC scenarios are presented in Appendix 4 (Tables A.2, A.3 and A.4). Appendix 6 shows that the wind and solar installed capacities stay well below the potential figures identified for France.

3.1.2. Emissions

The relationship between the social cost of carbon and the system's overall CO_2 emissions is presented in Figure 4. The power system becomes nearly carbon neutral for €100/tCO_2 and for €200/tCO_2 and above, emissions fall below zero. These negative emissions increase with the SCC, and at €500/tCO_2 the power system captures 12MtCO_2/year.

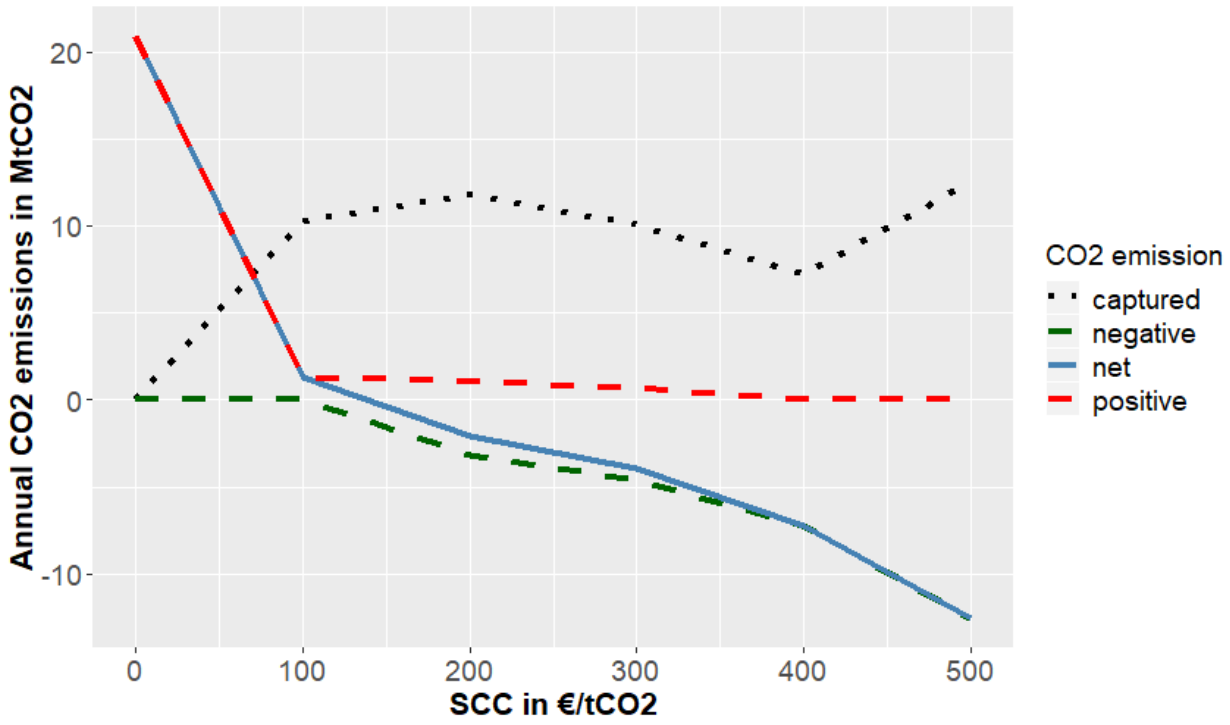

Figure 4. Annual positive, negative and net (net = positive – negative) CO_2 emissions and CO_2 captured by CCS technologies in $MtCO_2$/year for different SCC scenarios, for central VRE and nuclear power cost scenarios for 2050

One of the main hurdles to the deployment of CCS is the availability of enough safe storage sites. Hence Figure 4 presents the amount of captured CO_2 (from both fossil fuels and biomass), which gives a useful insight into the CO_2 storage required for each year.

3.1.3. Cost and revenues

We define two different system cost definitions: the technical cost (eq. (1) excluding the last part) and the cost including the social cost of carbon, i.e. the whole of eq. (1). In a decentralized equilibrium, the gap between these two costs would include the remuneration earned by negative CO_2-emitting plant operators and the tax paid by CO_2-emitting plant operators. Figure 5 shows these two costs for different SCC scenarios, for the central nuclear power and VRE cost scenarios. At €200/tCO_2 of SCC and more, these costs diverge significantly, and for €500/tCO_2, this gap reaches around €6bn/year i.e. around 20% of the technical cost.

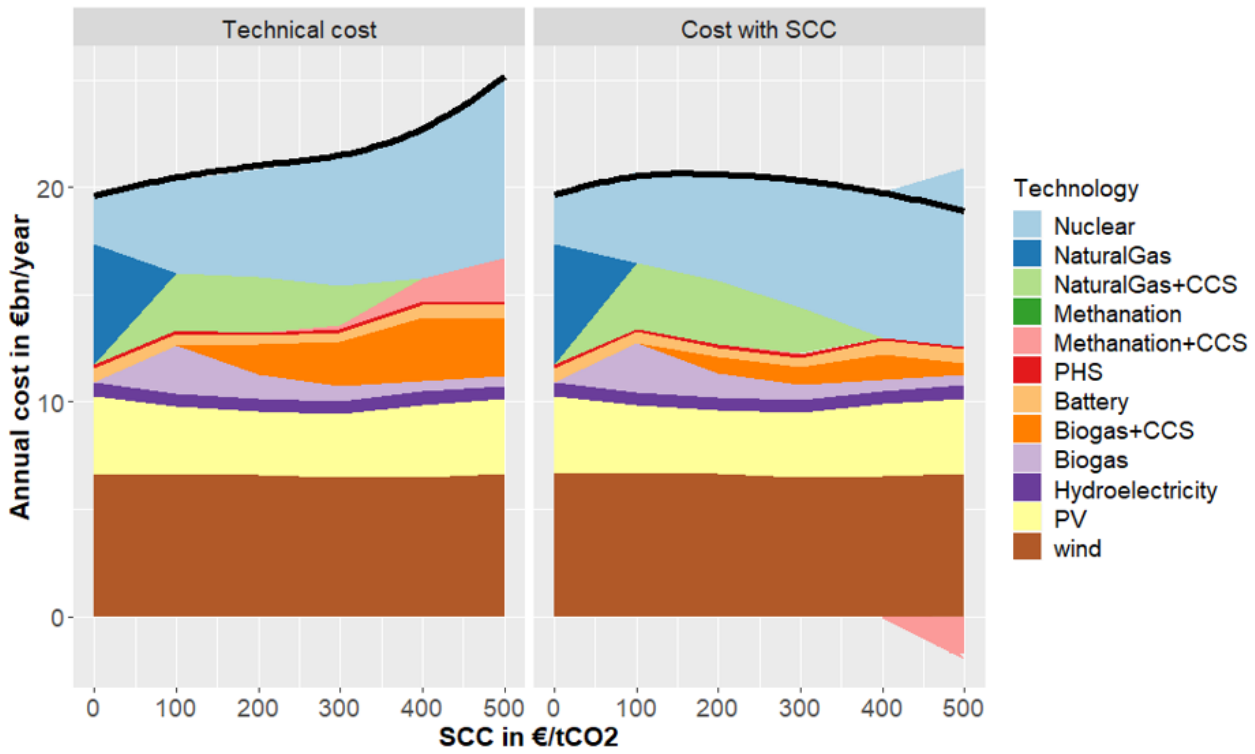

Figure 5. Annual technical cost and cost with social cost of carbon for central VRE and nuclear power cost scenarios, split by technology, for different SCC scenarios for 2050

Since we consider that positive and negative emissions are valued at the same price, in the case of positive CO_2 emissions the cost with SCC is higher than the technical cost of the system, and vice-versa in the case of negative emissions.

This large difference between the technical cost and the cost including the social cost of carbon raises another question: what is the proportion of CO_2-related revenues from CCS technologies in the overall revenues of the operators of technologies that include CCS? To answer this question, we first calculated the annual revenues from the electricity 'market' for each CCS technology and then the revenue (or expenditure) relating to negative (or positive) emissions. Figure 6 shows the revenues for each technology with CCS, from each of these two 'markets'.

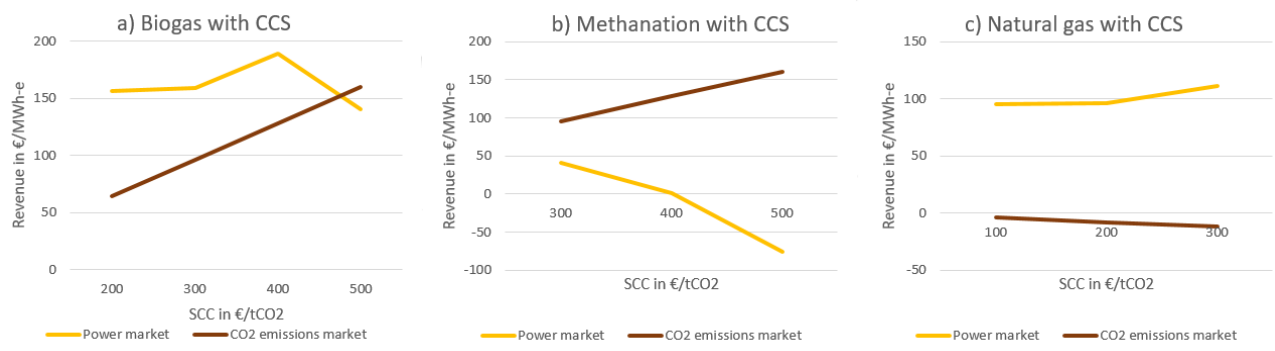

Figure 6. Proportion of revenues from electricity market and CO_2 emissions market for each technology with CCS, for central nuclear power and VRE cost scenarios for the considered time horizon (2050)

The electricity 'market' price is calculated from the dual of the adequacy equation (eq. 3). This hourly dual can be interpreted as the wholesale electricity price at each hour. The overall market revenues for each technology can be calculated by using this dual and the amount of electricity sold at each hour. For the storage technologies, money spent on buying electricity when the storage technologies are in the charging phase are deducted from the revenues. For the fuel technologies (biogas, natural gas and methanation), the revenues come from the gas market, whose price can be found using the dual of the combustion equations (equations (11) and (12)).

Since biogas and methanation with CCS are not used for SCCs of less than €200/tCO_2 and €300/tCO_2 respectively, and similarly since natural gas with CCS is only used for a SCC of €200/tCO_2 to €400/tCO_2, the graphs are limited to these values. We note that while biogas with CCS has a balanced revenue share from the two markets, for methanation with CCS above €400/tCO_2 the balance between expenditure and revenue in the power market is actually negative. Hence for a high carbon price, the development of the biogas+CCGT+CCS supply chain and to an even greater extent that of the methanation+CCGT+CCS supply chain would occur thanks to the remuneration of negative emissions rather than thanks to the electricity market.

3.1.4. Social acceptability of onshore wind power

To study the importance of social acceptability of onshore wind power, we defined an alternative limited social acceptability scenario for the onshore wind power with a maximal capacity limit of 34GW (i.e. twice the existing fleet).

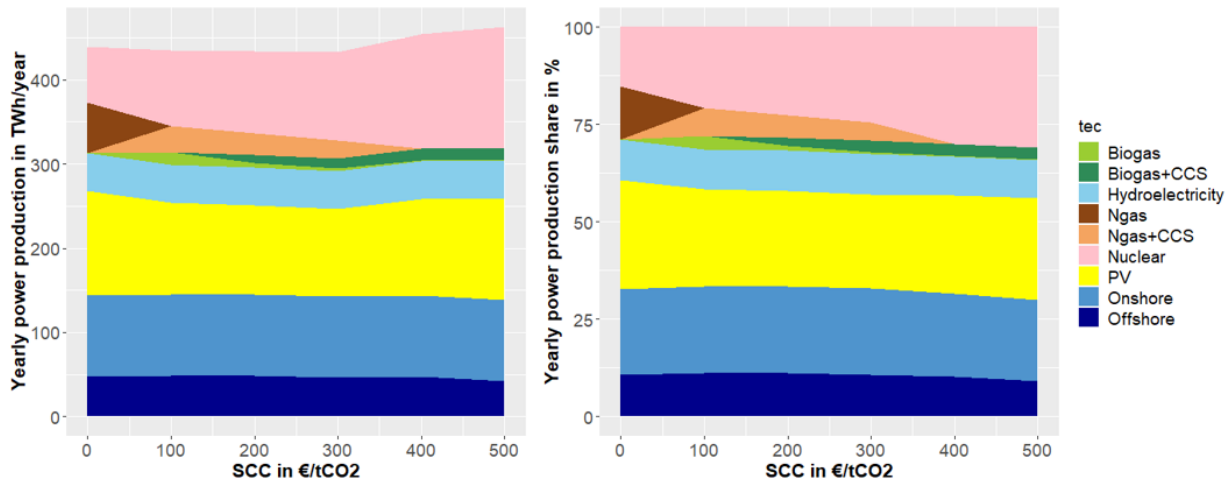

Figure 7 Electricity mix in TWh and in percentage share for the low social acceptability of onshore wind scenario as function of SCC for 2050

Comparison of figure 7 and figure 2 shows that while the power production by onshore wind decreases, an increase in the power production by offshore wind power keeps the wind power share higher than 25%. This slight decrease in the share of wind power in the overall power production leads to a slight increase in the share of nuclear power in the final electricity mix, but renewables still dominate the power sector and the share of nuclear power never surpasses 30% of the electricity production.

For every SCC scenario, we observed a negligible difference in system cost (less than 1% nearly for all SCC scenarios). The difference in CO_2 emissions is also lower than 2 Mt CO_2/year, except for a SCC of €500/tCO_2: 4.7 Mt CO_2/year. The main characteristics of this scenario can be found in Appendix 5.

3.1.5. How important is the availability of nuclear power and CCS technologies?

In this section, the importance of the nuclear power and the carbon capture and storage technologies has been studied, by removing first each of them separately, then both at once. This part of the study has only been performed for the central VRE and nuclear power cost scenarios. Figure 8 shows the system-wide Levelized Cost of Electricity (LCOE), i.e. the average system cost per unit power production, for each SCC scenario and for 4 different technology availability cases: a) with all technologies, b) without nuclear power, c) without CCS and d) with neither nuclear power nor CCS. The cost considered here includes the social cost of carbon.

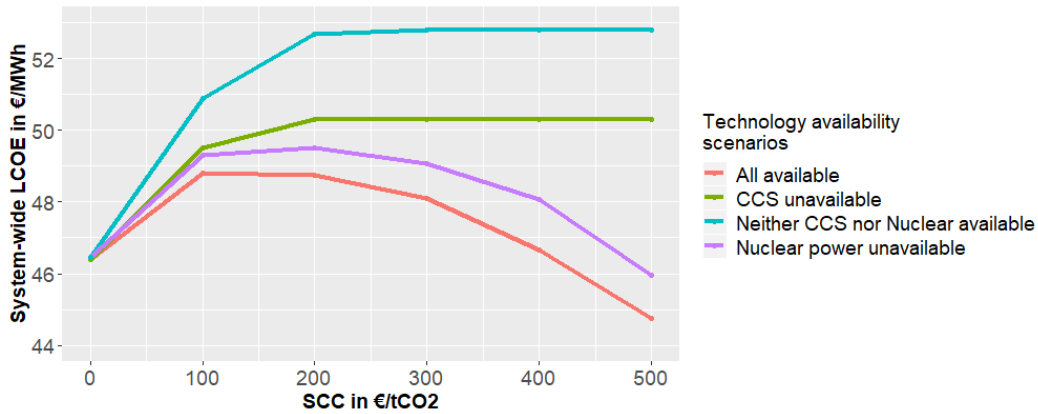

Figure 8. System-wide LCOE of the system for different technology availability scenarios, for central VRE and nuclear power cost scenario and different SCC scenarios for 2050

Since the negative emission remunerations come from CCS technologies combined with carbon neutral combustion technologies, the condition to decrease the system cost by increasing SCC is the availability of CCS technology. Availability of nuclear power leads to an average cost reduction of €2.5/MWh_e for SCC scenarios of €200/tCO_2 and more. The cost reduction from the availability of CCS is much higher, up to nearly €7/MWh_e, and both together can lead to a cost reduction of from €2/MWh_e for a SCC of €100/tCO_2 to €8/MWh_e for a social cost of carbon of €500/tCO_2.

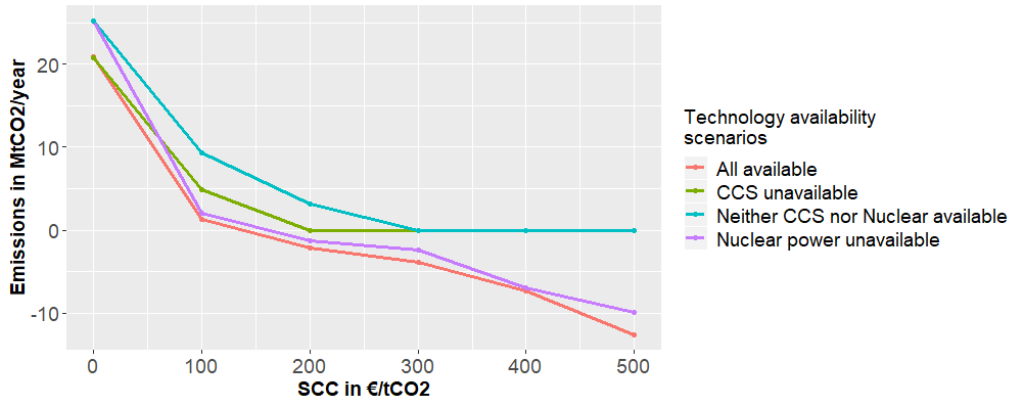

Figure 9. Annual CO_2 emission of power system for central VRE and nuclear power cost scenario, and different availability and SCC scenarios for 2050

The sensitivity of CO_2 emissions to the availability of technologies is presented in Figure 9. As shown previously, a nearly carbon neutral power system can be reached for a SCC of €100/tCO_2, but this happens only if CCS is available. If CCS is available, a SCC of €200/tCO_2 will result in negative emissions, while for the same SCC, the system with none of the technologies discussed above will not even reach carbon neutrality. To sum up, the system cost and emissions are more sensitive to the availability of CCS than to that of nuclear power.

3.2. Sensitivity to the relative cost of nuclear power and VRE technologies

Figure 10 shows the proportion of power produced by each technology. The proportions of renewables and nuclear are inversely related to their relative cost. Even for the most expensive VRE and cheapest nuclear scenario, nuclear power does not exceed 75% of the power mix. Conversely, for the low cost VRE scenario, it provides less than 15% of power production, and for most of the nuclear power cost scenarios (including the central one), nuclear power does not even enter the optimal power mix. On the other hand, the proportion of RES in power production almost never drops below 25%, while it can reach 100%.

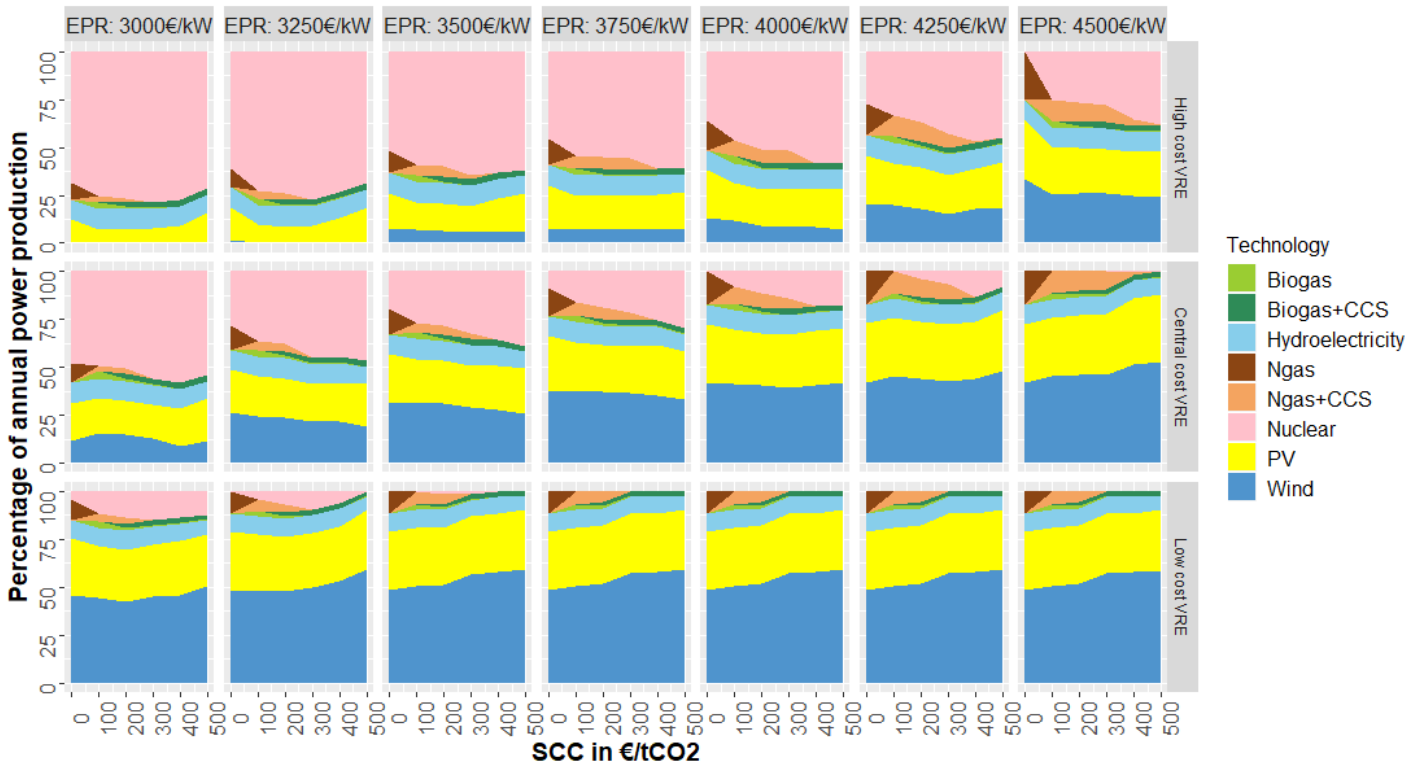

Figure 10. Annual percentage of power production for each technology for different VRE and nuclear power cost and SCC scenarios for 2050

While increasing the SCC leads to lower and even negative emissions, if decentralized in the form of public subsidies for negative emissions it also leads to a significant cost to the public purse. Figure 11 shows the annualized technical cost and the cost with the social cost of carbon. As we saw in Figure 5, for high SCC scenarios the gap between these two costs is large. The implied transfer can go up to €10.5bn/year for the low VRE cost and high SCC (€500/tCO_2) scenario, which also leads to higher negative emissions (approximately -22MtCO_2/year).

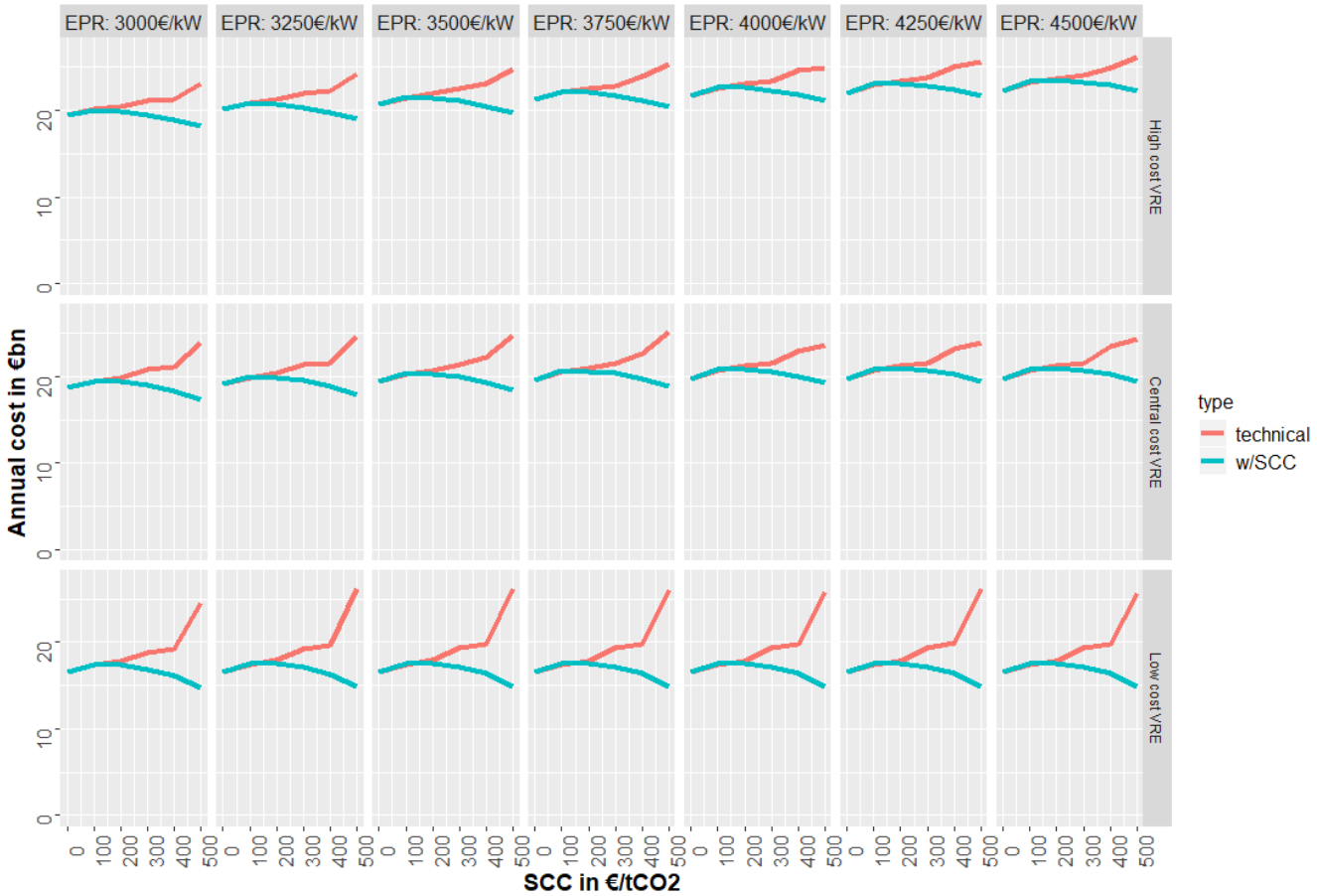

Figure 11. Annualized technical cost and cost with social cost of carbon (including SCC) for different VRE and nuclear power cost and SCC scenarios for 2050

As argued in section 3.1.2, the overall CO_2 emission gives helpful insights about the overall CO_2 balance, and the real carbon impact of the power system, but the required storage volume depends on the overall captured CO_2. Figure 12 shows the annual CO_2 emissions and annual captured CO_2 by CCS options for different VRE and nuclear power cost scenarios and different SCCs.

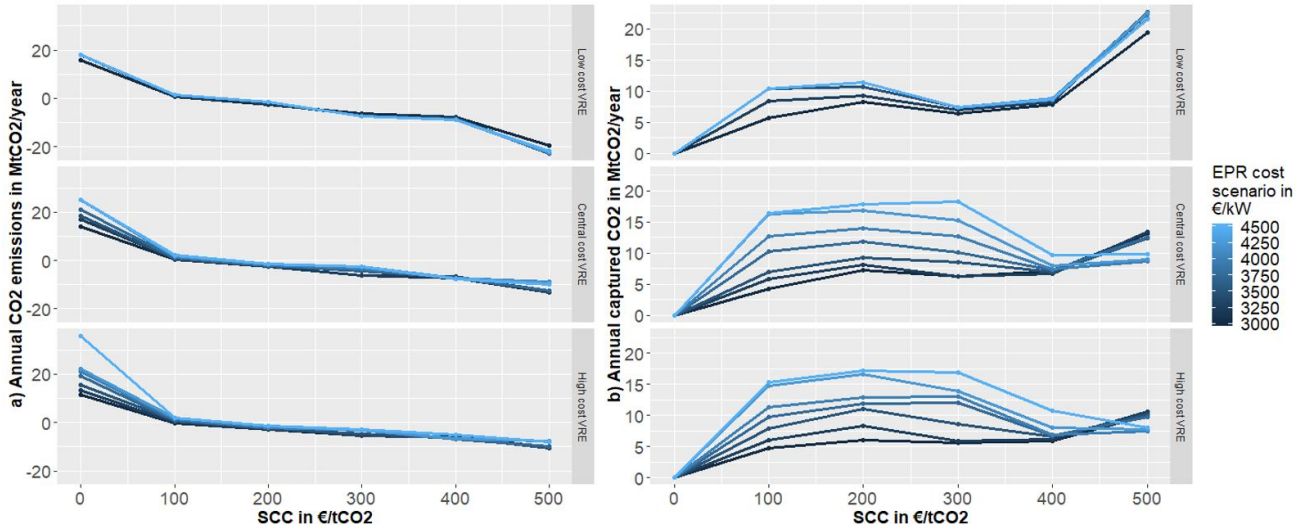

Figure 12. Overall a) annual net CO_2 emissions and b) annual captured CO_2 by CCS options for different VRE and nuclear power cost and SCC scenarios for 2050

Varying these cost scenarios can make a big difference to the amount of CO_2 captured. While for high and central VRE cost scenarios, the required storage does not exceed 18MtCO_2/year, the low VRE cost scenario leads to a storage capacity in excess of 20MtCO_2/year for €500/tCO_2 of SCC. The reason for this surge in negative emissions is the increased proportion of VRE technologies in the final electricity mix, which leads to an increased use of methanation. Similarly, high cost VRE leads to a high proportion of power production from nuclear power technology (60 to 75% of power production), which entails much less need for dispatchable options such as combustible technologies, which eventually capture more CO_2 for high SCC scenarios.

3.3. Importance of reduction in electricity demand

We use ADEME's central electricity demand hourly profile for 2050 (ADEME, 2015). This demand accounts for 422TWh$_e$/year, which is equivalent of the EFF (efficiency) scenario of the four main demand scenarios proposed in the French national energy transition debate (DNTE, 2013). The other scenarios are DIV (divergence – 534TWh$_e$/year), SOB (sobriety – 280TWh$_e$/year) and DEC (decarbonisation – 651TWh$_e$/year). To study the importance of reducing the electricity consumption, we ran the EOLES_elec model for two alternative demand scenarios: SOB (low demand) and DIV (high demand). Figure 13 shows the emission and system-wide LCOE of the power system for different SCC values and different demand levels.

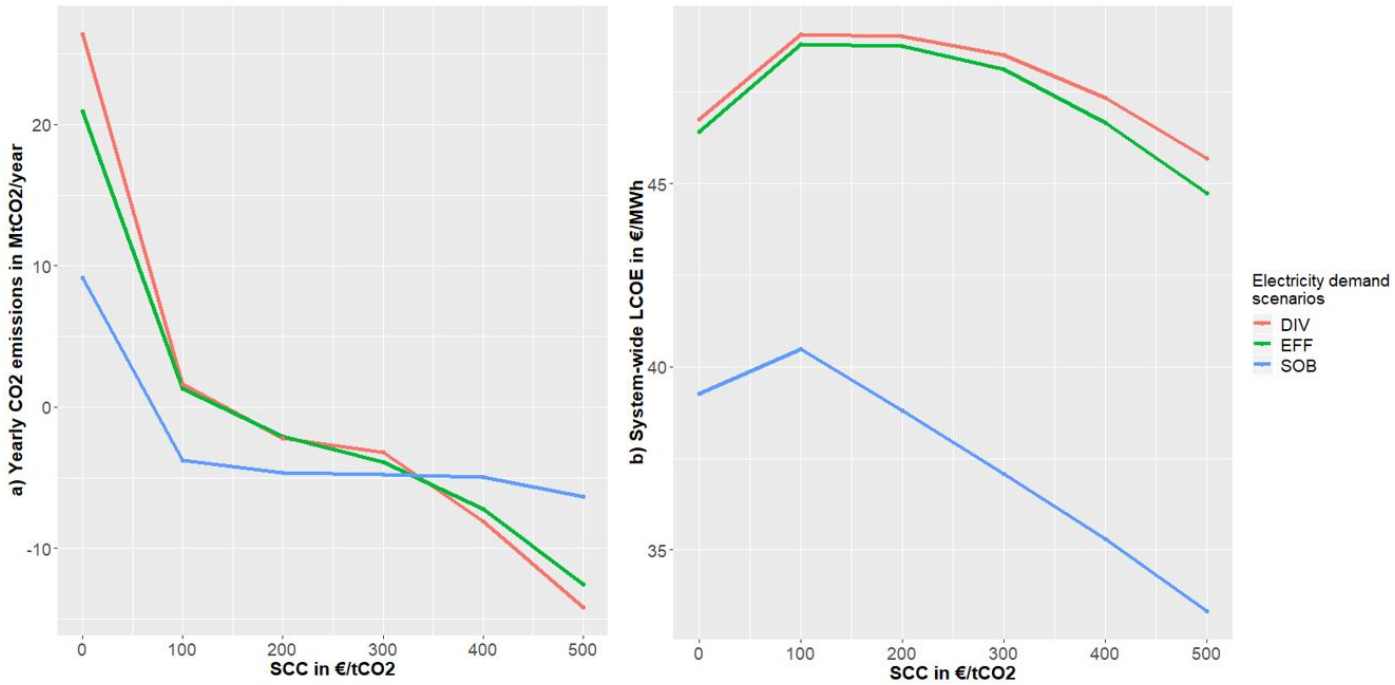

Figure 13 Impact of the electricity demand scenario on a) net CO_2 emissions and b) the system-wide levelized cost of electricity (including the social cost of carbon) for 2050

A low electricity demand leads to negative emissions for low SCC values (even 100€/tCO_2), but for a very high SCC, the amount of negative emissions decreases with electricity demand. Similarly, demand reduction does not only lower the total system cost (which is obvious) but also the system-wide LCOE, i.e. the cost per MWh consumed. The latter result stems mostly from the capacity and production constraints to hydro and biogas, which become less stringent (in percentage of electricity demand) under a lower electricity demand. The electricity mixes for different demand scenarios is presented in appendix 9.

4. Discussion

4.1. Comparison with existing studies for France

According to our findings, for moderate SCCs (€200/tCO_2 and less), the system-wide LCOE will be between €46/MWh_e and €50/MWh_e, depending on the availability of nuclear power and CCS technologies. If none is available, even for a very high social cost of carbon, this value will be less than €53/MWh_e. According to the latest quarterly report from the French energy regulator (CRE, 2019), 35% of a typical electricity bill (varying between €170 and €200/MWh_e depending on the tariff chosen and consumption profile) represents electricity production, which costs between €59-€70/MWh_e.

Therefore, even for high SCC scenarios, the power production side (including storage, grid connection and secondary reserve requirements) is estimated to cost less than today.

These results contrast with those of Krakowski et al. (2016), where the least costly scenario for France is presented as being "business as usual", and increasing the proportion of RES gradually increases the annualized cost of the power system by approximately 20% for an electricity mix with 80% of RES (€40bn/year). The main reasons for this difference in the results (20.5 to €22.3bn/year depending on the availability of technology and on the SCC scenario) are (i) lower VRE capacity potentials (70GW for wind and 65GW for solar power vs. 140GW for wind and 218GW for solar power in the current study) which results in very high power import costs, (ii) very low storage availability, and furthermore only short-term, very low-efficiency storage and (iii) the assumption of perfect correlation between offshore and onshore wind power, which leads to a lower complementarity between these technologies.

In a European-wide study Schlachtberger et al. (2018) find an annualized system cost that is very close to our findings (€20bn to €25bn depending on the wind availability scenario) for France, and in a further similarity to our previous findings (Shirizadeh et al. 2019) they observe considerable robustness of total system cost to the weather data and cost assumptions, but they find a higher proportion of power production by onshore wind. This difference in the installed capacity comes from small differences in the relative cost of technologies (the relative cost of onshore wind to offshore wind and solar PV is lower in Schlachtberger's study) and their exclusion of nuclear power and negative emissions technologies. Another difference that leads to a higher share of wind power in the final energy mix is the difference in the discount rate (4.5% vs. 7%), we studied the impact of the discount rate in the final energy mix in Appendix 6. Our findings confirm that a higher discount rate leads to a higher wind installed capacity.

According to another European-wide study (Brouwer et al. 2016), increasing the proportion of renewables in the final electricity mix from 40% to 80% raises the total system cost, even in the presence of demand response. The average system cost (average LCOE) is approximately €91/MWh_e for the case of 80% RES. This big difference in results can be explained by (i) the difference in the chosen future cost projections, where they use IEA's world energy investment outlook study (IEA, 2014), carried out in 2012, and projected for 2035, while since 2012 we have seen a very big cost decrease in solar PV and storage technologies, (ii) the non-negligible higher annual power demand (547TWh/year vs. 423TWh/year), (iii) a low calculated capacity factor for wind power (25% vs. 32.5%) which is also weakly correlated with the historical data (86% correlation), (iv) the choice of 2013 as the weather data year without studying the importance of this choice (in the current article the chosen representative weather

year is 2006, which results from a correlation study with a 19-year weather data simulation), and finally (v) the methodological difference in the calculation, where they use a two-stage procedure, first optimizing the installed capacity before optimizing the dispatch, while the EOLES_elec model optimizes dispatch and investment simultaneously.

In their study of the French power sector, Petitet et al. (2016) find an LCOE of €90/MWh_e for wind power and show that for a carbon price of less than €65/tCO_2 wind power is competitive with neither coal nor CCGT power plants. They also show that in the case of considering the existing nuclear power plants of France, for carbon prices below €150/tCO_2, wind power does not become economically competitive enough to enter the energy mix, while in the current article, we observe a very high proportion of RES, as shown in section 3.2. This big difference from our results comes from (i) not considering any storage options, (ii) using very different cost projection data (IEA and NEA's 2010 cost projections for electricity generation), (iii) the absence of negative emission technology option availability and (iv) considering onshore wind power as the only renewable source, moreover with a very low capacity factor (21.6% vs. 32.5%), based on the observation of the wind turbines installed at this time, which are much less efficient than state-of-the-art turbines (Hirth et al., 2016).

Several studies by ADEME focus on power mix planning for France. Among them, the "*100% renewable power mix"* study (ADEME, 2015), and "*electricity mix development trajectories 2020-2060"* (ADEME, 2018) explicitly optimize the power system and study the role of renewables in the French energy transition. Our results in the previous fully-renewable power mix study were very close to those of these two studies. But other options, especially CCS, may play an important role in cost reduction and reaching zero/negative emissions. Comparing our findings with ADEME's results, we highlight the importance of negative emission technologies.

To sum up, the main drivers of the different results from different studies are the assumptions about the cost components, availability of different technologies and the limiting constraints. More recent studies with up-to-date cost projections conclude with higher proportions of VRE in the final optimal electricity mix. Similarly, introduction of more precise weather data, as well as flexibility options and simultaneous optimization of dispatch and investment (which takes into account variable costs in the total cost minimization objective) can overcome the underestimation of the proportion of VRE in the power mix.

Finally, interconnections with neighboring countries, which are not included in our model, can significantly reduce the cost of a highly renewable system (Annan-Phan and Roques, 2018) because it

allows benefitting from the differences in climatic and weather conditions between the countries concerned.

4.2. CO_2 emissions and storage capacity

For a social cost of carbon of €100/tCO_2 and more, the CO_2 emissions are expected to be either zero or negative. Without any SCC, the CO_2 emission is approximately 20MtCO_2/year, which can be translated as 50kgCO_2/MWh_e. This figure is even higher for the expensive VRE and nuclear power cost scenarios. According to RTE's online portal (eco2mix)[o] the average emission rate of power production in France in 2018 was 60kgCO_2/MWh_e. Thus, in the absence of a SCC, the carbon dioxide emissions from the power sector would not decrease.

According to the IPCC (2005) special report on carbon capture and storage, the worldwide carbon dioxide storage capacity in saline formations is between 1,000 $\mathrm{GtCO_2}$ and 10,000 $\mathrm{GtCO_2}$ and the main onshore $\mathrm{CO_2}$ storage option for France is considered to be these saline formations. Kearns et al. (2017) estimate 8,000 to 55,000 $\mathrm{GtCO_2}$ of worldwide geological (onshore) $\mathrm{CO_2}$ storage capacity. Fuss et al. (2018) find the global carbon storage potential to be between 320GtCO_2 and 50,000GtCO_2, where the global estimates for aquifers is estimated at between 200GtCO_2 and 50,000GtCO_2. According to the *"Feasibility study for Europe-wide CO_2 infrastructure"* by the European commission (EC Directorate-General Energy, 2010), France is one of the few European countries having abundant carbon storage capacity for its own domestic production (more than 50 years of potential storage), and its ***total*** CO_2 storage capacity is estimated between 6GtCO_2 and 26GtCO_2. Yet according to CCFN (The Franco-Norwegian Chamber of Commerce)[p] *"(1) Onshore CO_2 storage in France, even if possible, could face strong social acceptance issues, (2) Up to 17-20 MtCO_2/year could be sent by ship from France (Le Havre and Dunkerque clusters mainly) to the North Sea for storage or CO_2 Enhanced Oil Recovery, (3) In the longer term, an additional 20 MtCO_2/year capacity pipeline could be laid parallel to the NorFra gas pipeline from a hub in Dunkerque"*. Hence, although the need for annual CO_2 storage is lower than these upper limits, French access to the North Sea and the availability of internal onshore storage still remain open questions.

We considered an upper limit of 15TWh$_e$/year for biogas from anaerobic digestion which is fully exploited in each SCC scenario. On the other hand, power-to-gas option of methanation can reach up to 20TWh$_e$/year for very high SCC scenarios. Therefore, one of the main enablers of a highly renewable

[o] https://www.rte-france.com/fr/eco2mix/chiffres-cles#chcleco2
[p] https://www.ccfn.no/actualites/n/news/french-norwegian-collaboration-on-carbon-capture-and-storage.html

zero or negative CO_2-emitting power is the biogas and biomethane injected to the gas network. In this study we did not take into account the methane leakage from gas network but using the existing gas infrastructure for biogas transmission and distribution might lead to methane leakage (Alvarez et al, 2012), eroding all the associated climate benefits (Union of concerned scientists, 2017). Therefore, a future work in analyzing methane leakage and its impact in the climate goals can be a complementary study with this paper.

4.3. Funding negative CO_2 emissions

In the case of a decentralized equilibrium, the difference between the technical cost and the cost with SCC requires pricing CO_2 by this amount, which could either be achieved by price instruments (taxes and subsidies) or by a CO_2 market. This market would reach up to €6bn/year for central nuclear power and VRE cost scenarios, and up to €10.5bn/year for the highest SCC scenarios. Considering the power system alone, negative emissions would need to be funded from the public purse, but since decarbonization of other CO_2 emitting sectors such as agriculture, industry and transport is more difficult, negative emissions in the power sector could be funded by taxing (or selling auctioned emission allowances for) the positive emissions from these sectors. In the second French national low carbon strategy report, the residual emissions for France are evaluated to be more than 80MtCO_{2eq}/year, assuming no negative emissions (SNBC, 2018). Negative emissions from the electricity sector could be one of the compensation options to help achieve net zero emissions by 2050.

4.4. Policy implications

For the vast majority of the scenarios studied, renewable technologies dominate the energy mix. The proportion of VRE in final electricity production varies from 60% to 70%, and it can go up to 90% for low VRE cost, high SCC scenarios. These findings are in line with the 70% to 85% of renewables in final electricity production obtained by Waisman et al (2019). Therefore, a fast development scheme for VRE technologies is of key importance in order to come into line with the Paris agreement objectives under the most cost-optimal conditions. Similarly, social acceptability of onshore wind power, as the main contributor to the electricity production, remains an important open question. Our findings indicate that limited social acceptability of this technology can lead to significant losses in the negative emission potential of the power system.

Since we perform a greenfield optimization, we have not included the option to refurbish the existing nuclear reactors. Provided that safety concerns do not preclude such refurbishment, the latter would likely be cheaper than building new nuclear plants. However, in 2050, only seven reactors out of the 56

currently operating in France will be less than 60 years old[q], and the youngest one will be 51 years old (excluding Flamanville III which is still under construction). Intuitively, if we included those seven existing reactors, they would replace the new reactors, presumably without changing the main results, beyond a small decrease in system cost.

Carbon dioxide emissions become null or negative if a taxation/remuneration scheme is implemented in the electricity market at a rate equal to the SCC value. The importance of CCS availability in order to achieve null and even negative emissions for low SCCs, and for lower costs, emphasizes the importance of this technology and its role in the future energy mix.

The projected CO_2 storage capacity, in the order of ~10Mt CO_2/year, shows an emerging need for geological storage which might be achieved either by exploiting the available French saline formations or transporting the captured carbon dioxide to the North Sea. Since the literature about the available storage capacity in France is very vague, further research is needed to quantify the existing internal carbon dioxide storage capacity nationwide. If storage in onshore saline formations is too difficult, commercial and political agreements with neighboring countries around the North Sea are the key solution for the availability of carbon capture and storage technologies.

5. Conclusion

This article examines the cost-optimal low-CO_2 energy mix for the French electricity sector. To that end, the EOLES_elec model, an electricity model from the EOLES family, has been developed to include six renewable technologies, conventional power production technologies (natural gas and nuclear power), natural gas with carbon capture and storage, and negative emission technologies (biogas with CCS and methanation storage with CCS). 126 cost scenarios have been built to assess a wide range of future cost projections for VRE and nuclear power technologies, as well as a wide range of social cost of carbon (SCC) scenarios.

This study's findings highlight the important role of renewable power generation technologies in the electricity mix, whose proportion is approximately 75% for the central cost scenario for VRE and nuclear power, whatever the level of SCC. Moreover, the relative proportion of nuclear power and renewable energy resources is very sensitive to the chosen cost scenario, but not to the SCC.

[q] The French nuclear industry does not claim that existing reactors may operate beyond 60 years, even following deep refurbishment.

Setting a SCC of €100/tCO_2 leads to the effective exploitation of CCS technology, where for most cost scenarios, the power system becomes carbon neutral and a SCC of €200/tCO_2 can be enough for the power system to reach negative emissions thanks to the appearance of BECCS technology in the optimal mix. While increasing SCC leads to an increased need for carbon storage, this required storage capacity does not exceed 20MtCO_2/year. Whether this amount of CO_2 can be stored in the French context remains an open question.

Depending on the cost projection and SCC scenarios, a carbon neutral, and even negative carbon emission power system will cost between €45/MWh_e and €49/MWh_e excluding grid-related costs and deducing the social benefit from negative emissions. This value remains well below the current electricity production cost in France. Availability of CCS technology plays an important role in achieving both carbon neutrality and cost reduction on the production side (5% to 18% cost reduction depending on the SCC scenario), while without CCS or the nuclear power system, the cost can rise to €53/MWh_e and even more for high VRE cost scenarios.

Finally, the gap between the cost with and without the social cost of carbon shows an emerging need for a public support scheme for negative emission technologies. This gap also shows the importance of carbon businesses which may emerge in high SCC scenarios, where the main incentive for negative emission technologies will only be to generate negative emissions which can be sold or subsidized, with less incentive to actually produce electricity.

This work could be extended in several directions, for instance, adding the interconnections with the neighboring countries can decrease the overall cost of the power system and help further exploitation of VRE technologies by adding the spatial aggregation possibility as a flexibility option for the intermittent energy sources. Similarly, while in this study the electricity demand is considered as inelastic series of parameters, separating different end-use demands by allowing the different energy carriers to satisfy each end-use demand endogenously would lead to more optimal allocation of supply, vector-change and storage capacities. In our electricity demand scenario half of the transport sector is electrified, while an optimal allocation of energy vectors for different transport end-use demands using plug-in battery electric vehicles, fuel cell electric vehicles, internal combustion engines with compressed biogas and biodiesel as well as existing conventional transport options might lead to different energy demand for different energy carriers. Inclusion of these flexible demand and interconnection would reinforce the findings of this study.

On the other hand, a highly renewable power system depends highly on the availability of bio-energies injected to the gas network, and in case of methane leakage, all the benefits from using biogas and biomethane options can be eroded. Thus, quantifying methane leakage and minimizing it in a narrower study of gas network is an important research question worth special attention.

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Appendices

Appendix 1. Wind and solar production 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 Rienecker et al. (2011),
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 Pierrot (2018), 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 Lauret et al. (2013) 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 Huld et al. (2010)'s relative PV performance model which gives temperature-dependent panel efficiency curves.

Appendix 2. Transport cost of carbon dioxide for methanation

The cost of transporting carbon dioxide along a 200km onshore pipeline is €$4/tCO_2$, for a 100km long pipeline, this transport cost can be assumed to be around €$2/tCO_2$. Given that each mole of carbon dioxide weighs 44 grams, and we can produce one mole of methane from one mole of CO_2 with an efficiency of 80% and each mole of methane can produce 802.3kJ of thermal energy, considering an OCGT combustion efficiency of 45% (JRC 2014):

$$\frac{1\ t\ CO_2}{1000000\ g\ CO_2} \times \frac{44\ g\ CO_2}{1\ mol\ CO_2} \times \frac{1\ mol\ CO_2}{0.8\ mol\ CH_4} \times \frac{1\ mol\ CH_4}{802.3\ kJ} \times \frac{1\ kJ\ th}{0.00022277778\ kWh\ th} \times \frac{1\ kWh\ th}{0.45\ kWh\ elec} \times \frac{1000\ kWh\ elec}{1\ MWh\ elec} = 0.5486 \frac{tCO_2}{MWh\ elec}$$

Multiplying this transport cost by €$2/tCO_2$, the CO_2 transport cost for methanation becomes €$1.0972/MWh$.

Appendix 3. Choice of the representative year

The selection of a representative year could be made using several criteria. We chose to select the year with a capacity factor closest to our 19-year optimal 100% renewable power mix. We used the capacity factor because it is invariable with respect to technology costs, on which we perform the sensitivity analysis. To measure the distance to the 19-year optimal mix, we compute the sum of absolute difference[r] of the three VREs. Using this approach, 2006 is the closest year to the overall 19-year period, with a sum of absolute error values of 1.5% (Table A.1). We launched the model with the optimal installed capacities found for 2006 over all other weather-years to test the adequacy of this installed capacity with respect to the other 18 weather-years, and we did not observe any operational inadequacy.

Table A.1. Choice of the representative year and its compatibility with each VRE technology

Representative year selection	Closest year	2nd closest year	3rd closest year
Offshore Wind	2011	2012	2006
Onshore Wind	2006	2004	2012
Solar PV	2004	2006	2009
Overall year	2006	2012	2004
Overall error (absolute)	1.5%	2.4%	2.8%

[r] Sum of normalized absolute differences $\sum_{i=1}^{3}\left|\frac{x_i - x^*{}_i}{x^*{}_i}\right|$ where x_i is the CF of each technology i in each year and $x^*{}_i$ is the CF of that technology over 18 years.

Appendix 4. installed capacities for the central cost scenarios

Table A.2. Installed capacity of each power production technology in GW for the central VRE and nuclear power cost scenarios

SCC (€/tCO_2)	Offshore Wind	Onshore Wind	Solar PV	Run-of-river	Lake & reservoir	OCGT	CCGT w/CCS	Nuclear power
0	0	58.5	91.8	7.5	12.9	33.4	0	5.3
100	5.4	48.9	80.3	7.5	12.9	20.1	9.9	10.3
200	5.5	48.3	75.2	7.5	12.9	13.8	15.7	12.1
300	6	46.3	75.7	7.5	12.9	10	17.5	14.3
400	0	57.1	85.5	7.5	12.9	7.9	15.6	16
500	0	58.9	89.7	7.5	12.9	8	13.1	19.7

Table A. 3. Installed capacity (and energy volume) of each storage technology in GW (and GWh/TWh) for the central VRE and nuclear power cost scenarios

SCC (€/tCO_2)	Battery (GW)	PHS (GW)	Battery (GWh)	PHS (GWh)	Methanation (TWh)	Methanation w/CCS (TWh)
0	15.1	9.3	40.2	180	0	0
100	12.8	9.3	29.4	180	0	0
200	11.2	9.3	21.1	180	0	0
300	11.2	9.3	21.1	180	0	3.26
400	14.2	9.3	36.5	180	0	16.88
500	14.8	9.3	38.9	180	0	16.93

Table A. 4 The main model outputs for the central VRE and nuclear power cost scenarios

SCC (€/tCO_2)	Annualized cost with SCC (€bn/year)	Annualized technical cost (€bn/year)	System-wide LCOE (€/MWh)	Average 'market price' (€/MWh)	Load curtailment (%)	CO_2 emissions (MtCO_2/year)
0	19.6	19.6	46.41	49.37	4.27	20.92
100	20.61	20.49	48.8	49.39	2.9	1.28
200	20.59	21.01	48.75	49.47	2.51	-2.09
300	20.32	21.49	48.11	49.65	2.08	-3.9
400	19.7	22.6	46.65	49.92	1.75	-7.25
500	18.9	25.18	44.74	50.19	1.48	-12.56

Appendix 5. installed capacities for limited onshore wind acceptability

Table A.5. Installed capacity of each power production technology in GW for the central VRE and nuclear power cost scenarios for limited onshore wind power acceptability

SCC (€/tCO_2)	Offshore Wind	Onshore Wind	Solar PV	Run-of-river	Lake & reservoir	OCGT	CCGT w/CCS	Nuclear power
0	10.31	34	86.8	7.5	12.9	31.6	0	8.96
100	10.48	34	76.63	7.5	12.9	19.88	9.41	12.89
200	10.48	34	74.71	7.5	12.9	13.16	14.71	14.35
300	10.03	34	73.13	7.5	12.9	9.84	17.26	15.76
400	10.22	34	80.54	7.5	12.9	7.63	15.14	18.56
500	9.06	34	85.23	7.5	12.9	6.98	15.03	18.77

Table A. 6. Installed capacity (and energy volume) of each storage technology in GW (and GWh/TWh) for the central VRE and nuclear power cost scenarios for limited onshore wind power acceptability

SCC (€/tCO_2)	Battery (GW)	PHS (GW)	Battery (GWh)	PHS (GWh)	Methanation (TWh)	Methanation w/CCS (TWh)
0	13.33	9.3	30.68	180	0	0
100	11.32	9.3	20.42	180	0	0
200	11.20	9.3	21.19	180	0	0
300	10.50	9.3	16.91	180	0	0
400	12.31	9.3	26.05	180	0	14.60
500	14.8	9.3	31.23	180	0	16.52

Table A. 7 The main model outputs for the central VRE and nuclear power cost scenarios for limited onshore wind power acceptability

SCC (€/tCO_2)	Annualized cost with SCC (€bn/year)	Annualized technical cost (€bn/year)	System-wide LCOE (€/MWh)	Average 'market price' (€/MWh)	Load curtailment (%)	CO_2 emissions (MtCO_2/year)
0	19.66	19.66	46.55	49.87	3.05	19.32
100	20.64	20.52	48.86	49.78	2.03	1.23
200	20.61	21.02	48.80	49.78	1.77	-2.05
300	20.34	21.30	48.15	49.78	1.63	-3.2
400	19.80	22.56	46.87	50.09	1.16	-6.91
500	19.06	22.99	45.14	50.19	1.25	-7.84

Appendix 6. Renewable capacities compared to potentials

Table A. 8 Renewable capacities in our study, capacities currently installed, capacities in other scenarios and available potential

	Optimum in reference cost scenario	Current capacity, mid-2019 (RTE, 2019)	Renewable potential			
			ADEME (2018)	Enevoldsen et al. (2019)	FEE (2019)	Cerema (2017)
Offshore wind	6GW	0GW	66GW	-	220GW	-
Onshore wind	59GW	17GW	174GW	300GW	-	-
Solar PV	92GW	10GW	459GW	-	-	776GW+ for south of France

For the reference cost scenario, the optimal mix features 0 to 6 GW of offshore wind (vs. 2 MW as of mid-2019), 46 to 59 GW of onshore wind (vs. 16 GW) and 75 to 92 GW of solar PV (vs. 9 GW). For each of the three technologies concerned, the capacity resulting from our optimization is much lower than those identified by the potential estimation studies (Table A.5). Hence there is no physical barrier to the implementation of these capacities.

However, many onshore wind projects suffer from local opposition, mostly related to landscape issues. This opposition may constitute the main obstacle to the implementation of the optimum mix that we have identified for our reference cost scenario. Indeed, reaching 59 GW in 2050 means an increase of 1.3 GW/yr. on average, from 2018 onwards, less than WindEurope's (2017) "high" 2030 scenario, but slightly more than the current rate of increase. Sustaining such a rate of increase is feasible, but requires a high degree of political determination, given the current opposition faced by many wind projects in France. On the other hand, we have seen that renewable technologies are by and large substitutable, so our intuition is that a scenario with less onshore, more offshore and more PV would not be much costlier.

Appendix 7. Sensitivity to the discount rate

As explained in section 2, the discount rate chosen is that proposed by Quinet (2014) for public socio-economic analyses, 4.5%. A sensitivity analysis has therefore been carried out for the discount rate (DR), from 2% to 7%. Figures A.1, A.2 and A.3 show the installed capacities, annual costs and annual CO_2 emissions for each SCC and DR scenario.

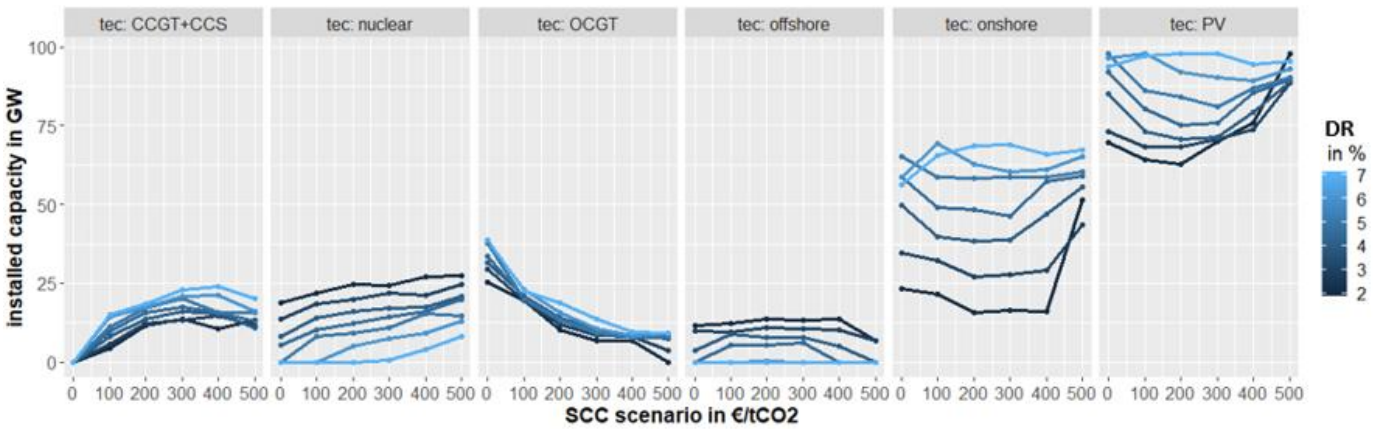

Figure A. 1. Installed capacity of each technology for different discount rate and social cost of carbon scenarios

Raising the discount rate increases the installed capacities of onshore wind and solar PV technologies, as well as gas turbines (both OCGT and CCGT with CCS); meanwhile, a higher discount rate reduces the proportion of nuclear and offshore wind because of their longer lifetime (60 and 30 years vs. 25 for onshore wind and PV). Moreover, the discount rate increases the annualized cost (Figure A.2), and Figure A.3 shows the linearity of this relationship.

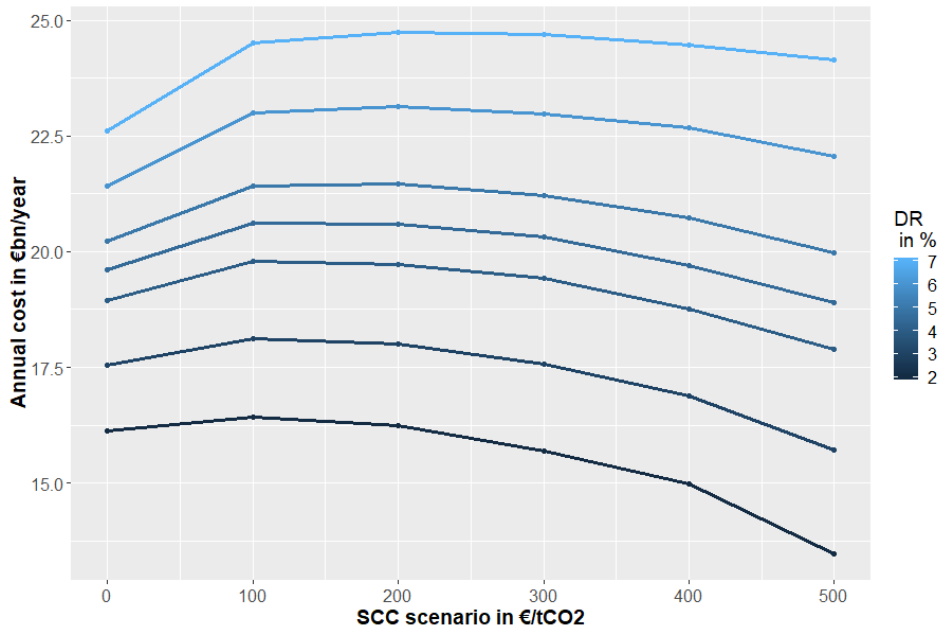

Figure A. 2. Annual total cost for each social cost of carbon and discount rate scenario

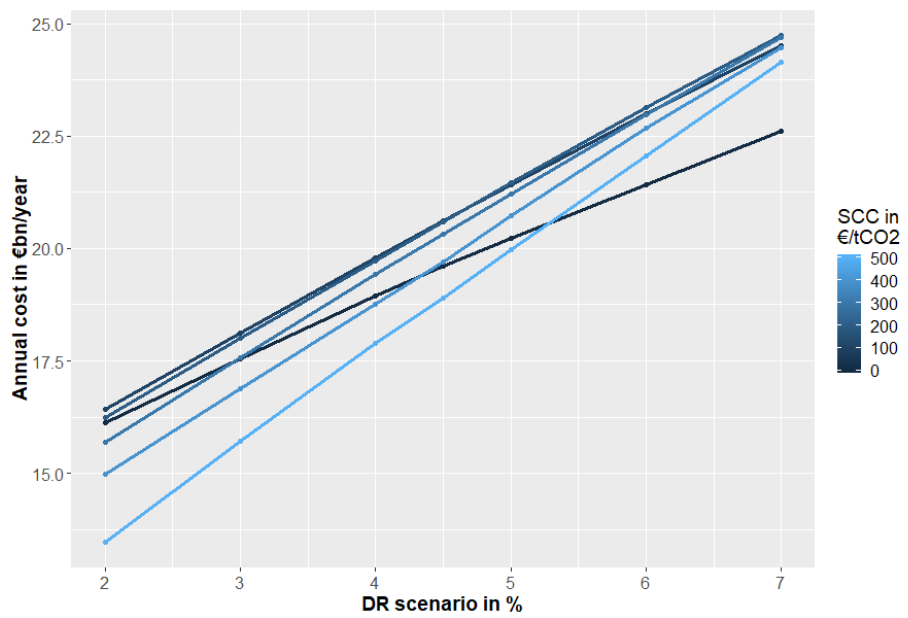

Figure A.3. Annual cost with respect to different SCC and discount rate scenarios

Figure A.3 shows that by increasing the SCC, the slope of this relationship increases, therefore the degree of cost dependence on the discount rate also increases. This can be explained as follows: increasing the discount rate favors the technologies with negative or positive emissions (OCGT and CCGT with CCS power plants) because of the low contribution of capital expenditure to their total costs.

Therefore, the sensitivity to the SCC (impacting the total cost to an even greater extent) also increases in this case.

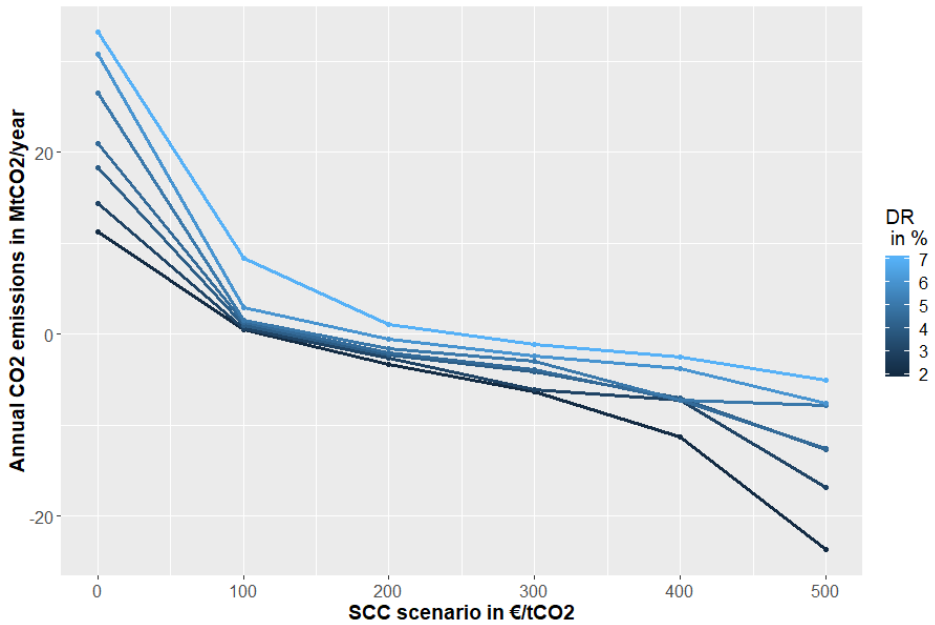

Figure A.4. Annual CO_2 emission for each social cost of carbon and discount rate scenario

Figure A.4 shows the impact of the discount rate on annual CO_2 emissions. As the discount rate increases, the proportions of zero-emission technologies (VRE technologies and nuclear power) decrease in comparison with both gas turbine technologies, therefore, the impact of variable costs (where fuel costs and SCC values are applied) becomes less significant in comparison with the investment costs. Emissions thus become higher e.g. with a discount rate of 7%, even for €200/tCO_2 of SCC value, annual CO_2 emissions are still positive, while for a discount rate of 2%, the lowest emissions are observed for each SCC scenario.

Appendix 8. installed capacities and power mix for the case with hydrogen storage and injection to the gas network

We studied the impact of presence of hydrogen in two different types of usage: direct injection to the gas network (limit to 6.35% of energetic volume of gas transport network, GRTgaz, 2019), and storage in salt caverns and separate hydrogen combustion with adapted CCGT power plants. Tables A.9 to A.11 present the installed capacities and the main power system characteristics for this variant scenario. The hydrogen storage with dedicated salt caverns never came out as an optimal technology, thus we excluded it from table A.10. Neither in energy mix, nor in other energy system characteristics we

observed a significant change compared to the case with only methanation as power-to-gas option. Therefore, to reduce the computation time of the model, we excluded both hydrogen options.

Table A.9. Installed capacity of each power production technology in GW for the central VRE and nuclear power cost scenarios for limited onshore wind power acceptability

SCC (€/tCO_2)	Offshore Wind	Onshore Wind	Solar PV	Run-of-river	Lake & reservoir	OCGT	CCGT w/CCS	Nuclear power
0	0	59.65	93.20	7.5	12.9	33.35	0	5.11
100	5.28	49.36	80.74	7.5	12.9	20.64	8.98	10.55
200	5.55	48.28	75.58	7.5	12.9	14.55	15.06	12.07
300	5.71	47.63	78.48	7.5	12.9	10.13	15.91	14.87
400	0	57.14	86.47	7.5	12.9	7.82	15.75	15.78
500	0	59.26	89.25	7.5	12.9	8.11	12.26	18.50

Table A. 10. Installed capacity (and energy volume) of each storage technology in GW (and GWh/TWh) for the central VRE and nuclear power cost scenarios for limited onshore wind power acceptability

SCC (€/tCO_2)	Battery (GW)	PHS (GW)	Hydrogen injection (GW)	Battery (GWh)	PHS (GWh)	Methanation (TWh)	Methanation w/CCS (TWh)	Hydrogen injection (TWh)
0	15.21	9.3	2.12	40.76	180	0	0	0.74
100	12.84	9.3	1.31	29.74	180	0	0	2.17
200	11.18	9.3	0.92	20.73	180	0	0	0.81
300	12.08	9.3	0.64	25.68	180	0	6.3	0.34
400	14.32	9.3	0.50	37.21	180	0	14.9	0.19
500	14.69	9.3	0.28	39.46	180	0	15.37	0.19

Table A. 11 The main model outputs for the central VRE and nuclear power cost scenarios for limited onshore wind power acceptability

SCC (€/tCO_2)	Annualized cost with SCC (€bn/year)	Annualized technical cost (€bn/year)	System-wide LCOE (€/MWh)	Average 'market price' (€/MWh)	Load curtailment (%)	CO_2 emissions (MtCO_2/year)
0	19.60	19.60	46.41	49.47	3.05	19.99
100	20.57	20.46	48.71	49.50	2.03	1.16
200	20.57	20.96	48.70	49.50	1.77	-1,97
300	20.27	21.84	47.99	49.75	1.63	-5,23
400	19.52	22.73	46.22	49.92	1.16	-8,03
500	18.26	24.78	43.24	50.12	1.57	-13.03

Figure A.5 shows the power supply mix. the difference of this figure from figure 2, and the tables A.9, A.10 and A.11 with tables A.2, A.3 and A.4 shows that exclusion of hydrogen has a negligible impact from the energy mix and economic optimality point of view.

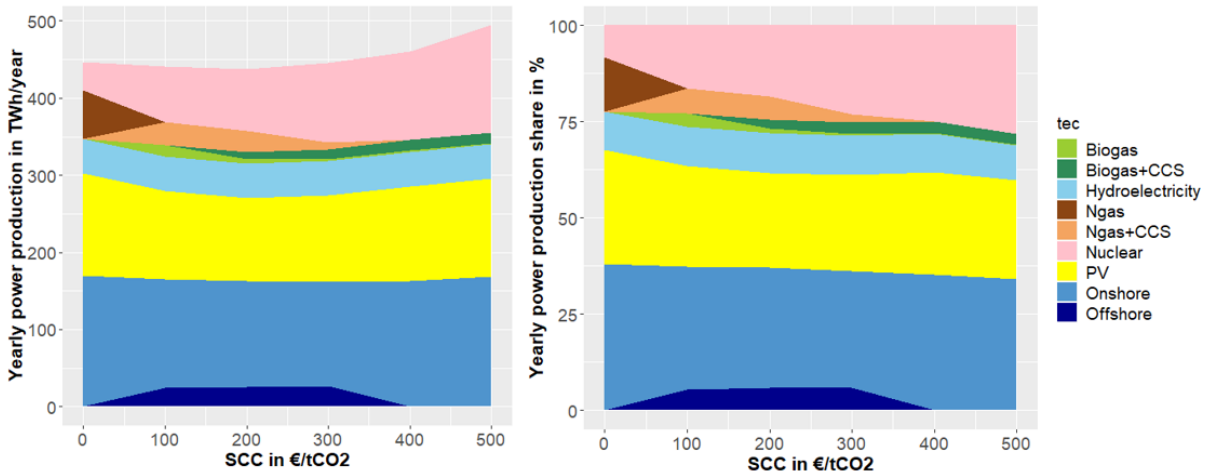

Figure A. 5 The power supply mix in TWh_e (left) and percentage share (right) for the scenario including hydrogen direct injection and storage

Appendix 9. Electricity mix for different demand scenarios

Figure A.6 shows the electricity mix for the central cost scenario, six SCC scenarios and three different electricity demand scenarios. We observe a steep increase in the nuclear power share in the electricity mix by increasing electricity demand (DIV). On the opposite, for a low electricity demand (SOB), nuclear power does not contribute significantly to electricity production and the use of fossil natural gas is massively reduced. Therefore, under a low demand scenario, the electricity mix is massively renewable (>90%) whatever the SSC.

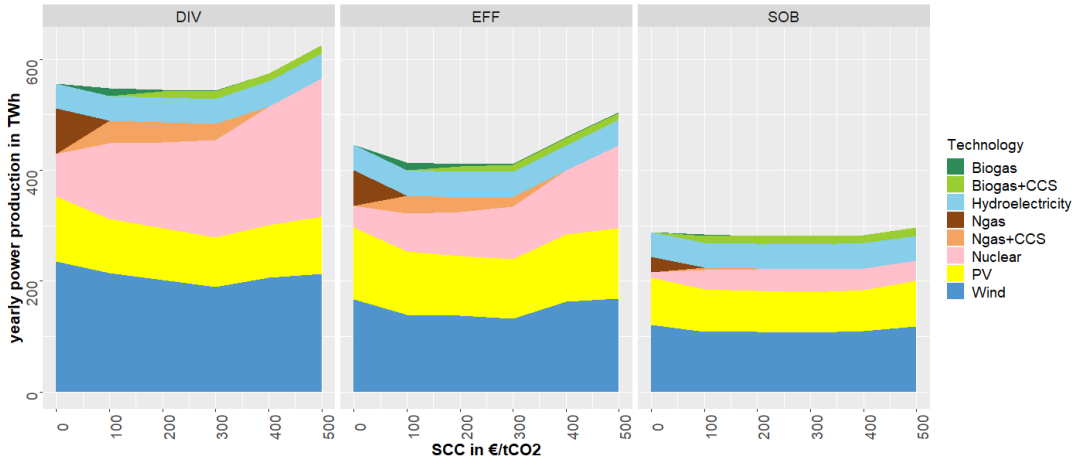

Figure A. 6 electricity mix for different demand and SCC scenarios