CIRED Working Paper
N° 2020-79 - Février 2020

EOLES_elec model description

Behrang Shirizadeh
Philippe Quirion

Corresponding author: shirizadeh@centre-cired.fr

Centre international de recherche sur l'environnement et le développement
Unité mixte de recherche CNRS - Ecole des Ponts ParisTech - Cirad - EHESS - AgroParisTech
Site web: www.centre-cired.fr   Twitter: @cired8568
Jardin Tropical de Paris -- 45bis, avenue de la Belle Gabrielle 94736 Nogent-sur-Marne Cedex

EOLES_elec model description

Behrang Shirizadeh[1,2]* and Philippe Quirion[1]

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

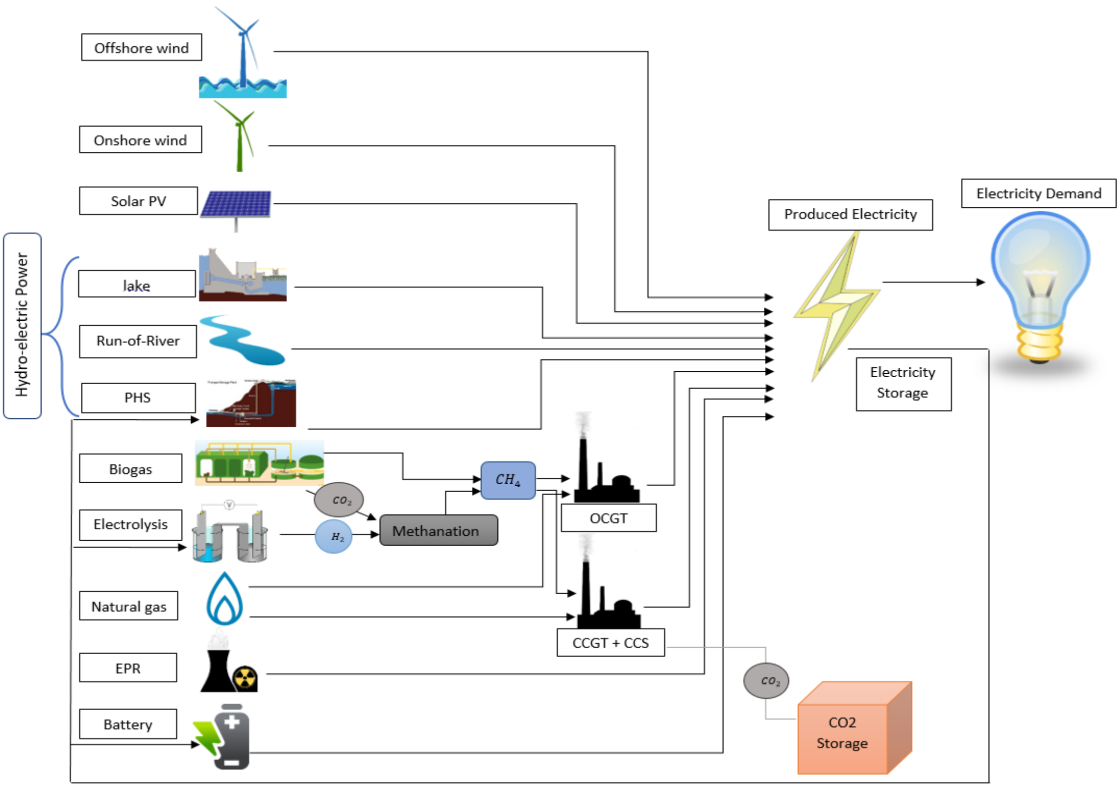

Figure 1. Graphical description of the EOLES_elec model

[1] CIRED-CNRS, 45 bis avenue de La Belle Gabrielle, 94736 Nogent sur Marne Cedex, France
[2] TOTAL, GRP, R&D department, 2 place Jean Millier, 92078 Paris la Défense Cedex, France.
* Corresponding author: shirizadeh@centre-cired.fr, +33 (0)1 43 94 74 78

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: non-linear constraints might improve accuracy, especially when studying unit commitment, however they entail significant 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. The model is written in GAMS and solved using the CPLEX solver. The code and data are available on Github.[3]

The remainder of this document presents the used input parameters and resulting variables, main equations of the model and suggested values for France for 2050. Sections 1 and 2 represent sets, parameters and variables of EOLES_elec model respectively. The equations are presented in section 3, and the suggested input parameters are presented in section 4.

1. Sets and parameters

Table 1 presents the sets and indices of the EOLES_elec model and table 2 the parameters. Throughout the paper, every energy unit (e.g. MWh) or power unit (e.g. MW) is expressed in electricity-equivalent. For instance, some energy is stored in the form of methane, to be transformed later into electricity using open-cycle natural gas plants with 45% efficiency. In this case, when we indicate that 45 MWh_e is stored in the natural gas network, it means that 100 MWh of methane is stored, which will allow 45 MWh_e of electricity to be generated.

Table 1 Sets and indices of the EOLES_elec model

Index	Set	Description
h	∈ H	**Hour:** the number of hours in a year, from 0 to 7659
m	∈ M	**Month:** the twelve months, from January to December
tec	∈ TEC	**Technologies:** The set of all electricity generation and energy storage technologies (offshore, onshore, PV, river, lake, nuclear, biogas, OCGT,CCGT with CCS, PHS, battery, methanation)
gen	∈ GEN ⊆ TEC	**Generation:** Electricity generation technologies (offshore, onshore, PV, river, lake, nuclear, biogas, OCGT,CCGT with CCS)
vre	∈ VRE ⊆ TEC	**VRE:** Variable renewable electricity generation technologies (offshore, onshore, PV)
str	∈ STR ⊆ TEC	**Storage:** Energy storage technologies (PHS, battery, methanation)
$ncomb$	∈ NCOMB ⊆ TEC	**Non-combustible** generation technologies (offshore, onshore, PV, river, lake, nuclear, PHS, battery)
$comb$	∈ COMB ⊆ TEC	**Combustible** generation technologies (biogas, methanation)
frr	∈ FRR ⊆ TEC	**Frequency restauration reserves:** Technologies contributing to secondary reserves requirements (lake, PHS, battery, OCGT, CCGT with CCS and nuclear)
scc	∈ SCC	**Social cost of carbon scenario:** The scenarios are 0, 100, 200, 300, 400 and 500€/tCO_2

[3] https://github.com/BehrangShirizadeh/EOLES_elec

Table 2 Parameters of the EOLES_elec model

Parameter[4]	Unit	Description
$month_h$	[-]	A parameter to show which month each hour is in
$cf_{vre,h}$	[-]	Hourly production profiles of variable renewable energies
$demand_h$	$[GW_e]$	Hourly electricity demand profile
$lake_m$	$[GWh_e]$	Monthly extractable energy from lakes
$river_h$	[-]	Hourly run-of-river capacity factor profile
ε_{vre}	[-]	Frequency restoration requirement because of forecast errors on the production of each variable renewable energy
q_{tec}^{ex}	$[GW_e]$	Existing capacity by technology
$annuity_{tec}$	[M€/GW_e/year]	Annualized capital cost of each technology
$annuity_{str}^{en}$	[M€/GWh/year]	Annualized capital cost of energy volume for storage technologies
$capex_{str}^{ch}$	[M€/GW /year]	Annualized capital cost of storage technology charging power
$fO\&M_{str}^{ch}$	[M€/GW /year]	Fixed operation and maintenance cost of storage technology charging power
$fO\&M_{tec}$	[M€/GW_e /year]	Annualized fixed operation and maintenance cost
$vO\&M_{tec}$	[M€/GWh_e]	Variable operation and maintenance cost of each technology
η_{str}^{in}	[-]	Charging efficiency of storage technologies
η_{str}^{out}	[-]	Discharging efficiency of storage technologies
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
e_{biogas}^{max}	$[TWh_e]$	Maximum yearly energy that can be generated from biogas
$\delta_{uncertainty}^{load}$	[-]	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_{ccgt}	[-]	The maximal annual capacity factor for CCGT plant

[4] The suggested values for France are available in GitHub page presented above.

2. Variables

The variables resulting from the optimization are presented in table 3.

Table 3 Variables of EOLES_elec model

Variable	**Unit**	**Description**
$G_{tec,h}$	GWh_e	Hourly electricity generation by technology
Q_{tec}	GW_e	Installed capacity by technology
$STORAGE_{str,h}$	GWh_e	Hourly electricity entering each storage technology (inflow)
$STORED_{str,h}$	GWh_e	Hourly energy stored in each technology (stock)
S_{str}	GW_e	Installed charging capacity by storage technology
$VOLUME_{str}$	GWh_e	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 power system cost annualized (minus the fixed cost of already installed capacities). This is the objective function to be minimized.

3. Equations

3.1. 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 $€/kW_e$ ($capex^{ch}_{str}$), the second proportional to the energy capacity in $€/kWh_e (annuity^{en}_{str})$.

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

where Q_{tec} represents the production capacities, q^{ex}_{tec} 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, $capex^{ch}_{str}$ is the charging annualized investment cost and $fO\&M^{ch}_{str}$ 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.

3.2. 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*.

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 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.

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 5):

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

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.

3.5. 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:

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

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, $\delta^{load}_{variation}$ is the load variation factor and $\delta^{load}_{uncertainty}$ 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).

3.6. 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.

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

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).

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

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).

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

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):

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

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).

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

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:

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

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:

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

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

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:

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

It is worth to mention that according to Agora energiewende (2017), the ramping rates (both upward and downward) for OCGT and CCGT power plants can go easily 100% in less than an hour. 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 Mac Dowell et al. (2016) 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.

3.7. 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.

3.8. 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 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):

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

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.

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

4. Suggested input parameters

4.1. VRE profiles

Variable renewable energies' (offshore and onshore wind and solar PV) hourly capacity factors have been prepared using the renewables.ninja website[5], 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 Pfenninger and Staffell (2016) and Staffell and Pfenninger (2016). 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 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[6], 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.

4.2. 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.

4.3. 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

[5] https://www.renewables.ninja/
[6] https://www.4coffshore.com/

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[7].

4.4. Economic parameters

Table 4 summarizes the economic parameters (and their sources) used as input data in EOLES model.

Table 4 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 (%)**	**Source**
*Offshore wind farm**	2,330	30	150.9	47	0	1	-	JRC (2017)
*Onshore wind farm**	1,130	25	81.2	34.5	0	1	-	JRC (2017)
*Solar PV**	423	25	30.7	9.2	0	0.5	-	JRC (2017)
Hydroelectricity – lake and reservoir	2,275	60	115.2	11.4	0	1	-	JRC (2017)
Hydroelectricity – run-of-river	2,970	60	150.4	14.9	0	1	-	JRC (2017)
Biogas (Anaerobic digestion)	2,510	25	141.6	83.9	3.1	1	-	JRC (2017)
Natural gas	-	-	-	-	50/61**	-	-	IEA (2018)
Nuclear power	3,750	60	262.6	97.5	9.5***	10	38%	JRC (2014)
CCGT with CCS	1,280	30	82.1	32	18****	1	55%	JRC (2017)
OCGT	550	30	35.3	16.5	-	1	45%	JRC (2014)

*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. **€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

[7] https://www.rte-france.com/fr/eco2mix/eco2mix-telechargement

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 (23):

$$IDC = \sum_{j=1}^{ct} C_j[(1+r)^{t_{op}-j} - 1] \qquad (23)$$

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 5 shows the economic parameters of power storage technologies.

Table 5. 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.

4.5. 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 6.

Table 6. 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)

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 7. Country-specific limiting input parameters of model

parameter	definition	value	source
$lake_m$*	Monthly maximum electricity from dams & reservoirs	See GitHub[8]	RTE (2016)
$river_h$**	Hourly maximal power production from run-of-river	See GitHub[9]	RTE (2016)
e_{biogas}^{max}	Annual maximal power production from Biogas	15TWh	ADEME (2013)
q_{tec}^{max}	Maximum installable capacity limit for each technology	See GitHub[10]	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[11] (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.

[8] https://github.com/BehrangShirizadeh/EOLES_elec/blob/master/lake_inflows.csv
[9] https://github.com/BehrangShirizadeh/EOLES_elec/blob/master/run_of_river.csv
[10] https://github.com/BehrangShirizadeh/EOLES_elec/blob/master/max_capas.csv
[11] https://www.rte-france.com/fr/eco2mix/eco2mix-telechargement

4.6. 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:

$$annuity_{tec} = \frac{DR \times CAPEX_{tec}((DR \times ct_{tec}) + 1)}{1 - (1 + DR)^{-lt_{tec}}} \quad (24)$$

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 6 provides a sensitivity analysis, varying this rate from 2% to 7%.

References

ADEME (2013). L'exercice de prospective de l'ADEME "Vision 2030-2050" - document technique.

ADEME (2015). *Vers un mix électrique 100 % renouvelable*. https://www.ademe.fr/sites/default/files/assets/documents/mix-electrique-rapport-2015.pdf.

ADEME (2018). Trajectoires d'évolution du mix électrique à horizon 2020-2060. ISBN: 979-10-297-1173-2

Agora energiewende (2017). *Flexibility in Thermal Power Plants*.

Arditi, M., Durdilly, R., Lavergne, R., Trigano, É., Colombier, M., Criqui, P. (2013). Rapport du groupe de travail 2: Quelle trajectoire pour atteindre le mix énergétique en 2025 ? Quels types de scénarios possibles à horizons 2030 et 2050, dans le respect des engagements climatiques de la France ? Tech. rep., Rapport du groupe de travail du conseil national sur la Transition Energétique.

CRE (2018). *Observatoire des marchés de détail de l'électricité et du gaz naturel du 3e trimestre 2018*. https://www.cre.fr/content/download/20125/256999.

ENEA Consulting (2016). The potential of Power-to-Gas. https://www.enea-consulting.com/sdm_downloads/the-potential-of-power-to-gas/

ENTSO-E (2013). Network Code on Load-Frequency Control and Reserves 6, 1–68.

Ericsson, K. (2017). "Biogenic carbon dioxide as feedstock for production of chemicals and fuels: A techno-economic assessment with a European perspective." Environmental and Energy System Studies, Lund University: Miljö- och energisystem, LTH, Lunds universitet.

FCH JU (2015). Commercialisation of energy storage in Europe: Final report.

Gen IV International Forum (2007): Cost estimating guidelines for Generation IV nuclear energy systems, Revision 4.2, GIF/EMWG/2007/004.

JRC (2014) *Energy Technology Reference Indicator Projections for 2010–2050*. EC Joint Research Centre Institute for Energy and Transport, Petten.

JRC (2017) *Cost development of low carbon energy technologies - Scenario-based cost trajectories to 2050*, EUR 29034 EN, Publications Office of the European Union, Luxembourg, 2018, ISBN 978-92-79-77479-9, doi:10.2760/490059, JRC109894.

Mac Dowell, N., & Staffell, I. (2016). The role of flexible CCS in the UK's future energy system. International Journal of Greenhouse Gas Control, 48, 327-344.

Moraes, L., Bussar, C., Stoecker, P., Jacqué, K., Chang, M., & Sauer, D. U. (2018). "Comparison of long-term wind and photovoltaic power capacity factor datasets with open-license." Applied Energy 225, 209-220.

NEA (2011): Technical and Economic Aspects of Load-following with Nuclear Power Plants, OECD/NEA. www.oecd-nea.org/ndd/reports/2011/load-followingnpp.pdf

NEA (2018): Measuring Employment Generated by the Nuclear Power Sector (No. NEA--7204). [Alexeeva, V., Molloy, B., Beestermoeller, R., Black, G., Bradish, D., Cameron, R., ... & Emeric, J.] Organisation for Economic Co-Operation and Development.

Palmintier, B. (2014). Flexibility in generation planning: Identifying key operating constraints. In *2014 power systems computation conference* (pp. 1-7). IEEE, August.

Perrier, Q. (2018). "The second French nuclear bet." Energy Economics, 74, 858-877.

Pfenninger, S., Staffell, I. (2016). "Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data." Energy 114, pp. 1251-1265. doi: 10.1016/j.energy.2016.08.060

Quinet, E. (2014). L'évaluation socioéconomique des investissements publics (No. Halshs 01059484). HAL.

RTE (2018), Panorama de l'électricité renouvelable au 30 Juin 2018.

Shirizadeh, B., Perrier, Q., & Quirion, P. (2019). How sensitive are optimal fully renewable power systems to technology cost uncertainty? FAERE PP 2019.04.

Schmidt, O., Melchior, S., Hawkes, A., Staffell, I. (2019). "Projecting the Future Levelized Cost of Electricity Storage Technologies." Joule ISSN 2542-4351 https://doi.org/10.1016/j.joule.2018.12.008

Staffell, I., Pfenninger, S. (2016). "Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output." Energy 114, pp. 1224-1239. doi: 10.1016/j.energy.2016.08.068

Van Stiphout, A., De Vos, K., & Deconinck, G. (2017). "The impact of operating reserves on investment planning of renewable power systems." IEEE Transactions on Power Systems, 32(1), 378-388.

ZEP (2011). *The Costs of CO_2 Transport. Post-demonstration CCS in the EU.* Zero Emissions Platform. http://www.zeroemissionsplatform.eu/downloads/813.html