Application of EnergyScope TD to the Belgium case
Supplementary Material

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Introduction

This Supplementary Material presents the complete formulation of the energy model (Section 1). In addition, all the data used for the case and their sources are presented in Section 2. The latest version of this Supplementary Material is available on the repository[1].

1 Linear programming formulation

The model is mathematically formulated as a linear programming (LP) problem [1]. We use the following nomenclature: *SETS* are in italic capital letters, *parameters* are in italic lower letters and **Variables** are bold in lower letter, with the first letter in capital (e.g. $\mathbf{C_{tot}}$). *SETS* are collections of distinct items (as in the mathematical definition), e.g. the *RESOURCES* set regroups all the available resources (NG, WOOD, etc.). *Parameters* are known values (inputs) of the model, such as the demand or the resource availability. The value of the decision variables is determined (optimized) by the solver within an upper and a lower bound (the latter being parameters). As an example, the quantity of installed wind turbines is a decision variable; this quantity is bounded between 0 and the maximum available potential. *Decision variables* can be split in two categories: independent decision variables, which can be freely fixed, and dependent decision variables, which are linked via equality constraints to the previous ones. As an example the investment cost for wind turbines is a variable but it directly depends on the number of wind turbines, which is an independent decision variable. *Constraints* are inequality or equality restrictions that must be satisfied. Constraints can enforce, for example, an upper limit for the availability of resources, energy or mass balance, etc. Finally, an *objective function* is a particular constraint whose value is to be maximised (or minimised).

1.1 Conceptual modelling framework

The proposed modelling framework is a simplified representation of an energy system accounting for the energy flows within its boundaries. Its primary objective is to satisfy the energy balance constraints, meaning that the demand is known and the supply has to meet it. In the energy modelling practice, the energy demand is often expressed in terms of final energy consumption (FEC). According to the definition of the European commission, FEC is defined as "*the energy which reaches the final consumer's door*" [2]. In other words, the FEC is the amount of input energy needed to satisfy the end-use demand (EUD) in energy services. As an example, in the case of decentralised heat production with a natural gas (NG) boiler, the FEC is the amount of NG consumed by the boiler; the EUD is the amount of heat produced by the boiler, i.e. the heating service needed by the final user.

The input for the proposed modelling framework is the EUD in energy services, represented as the sum of four components: electricity, heating, mobility and non-energy demand; this replaces the classical sector-based representation of energy demand. Heat is divided in three end-use types (EUTs): high temperature heat for industry demand, low temperature for space heating and low temperature for hot water. Mobility is divided in two EUTs: passenger mobility and freight[2]. Non-energy demand is, based on the International Energy Agency (IEA) definition, "*fuels that are used as raw materials in the different sectors and are not consumed as a fuel or transformed into another fuel.*" [3]. As examples, the European Commission includes

[1] Repository:**TBD**

[2] Passenger transport activity from aviation is accounted in passenger mobility (excluding international extra-European Union (EU) aviation).

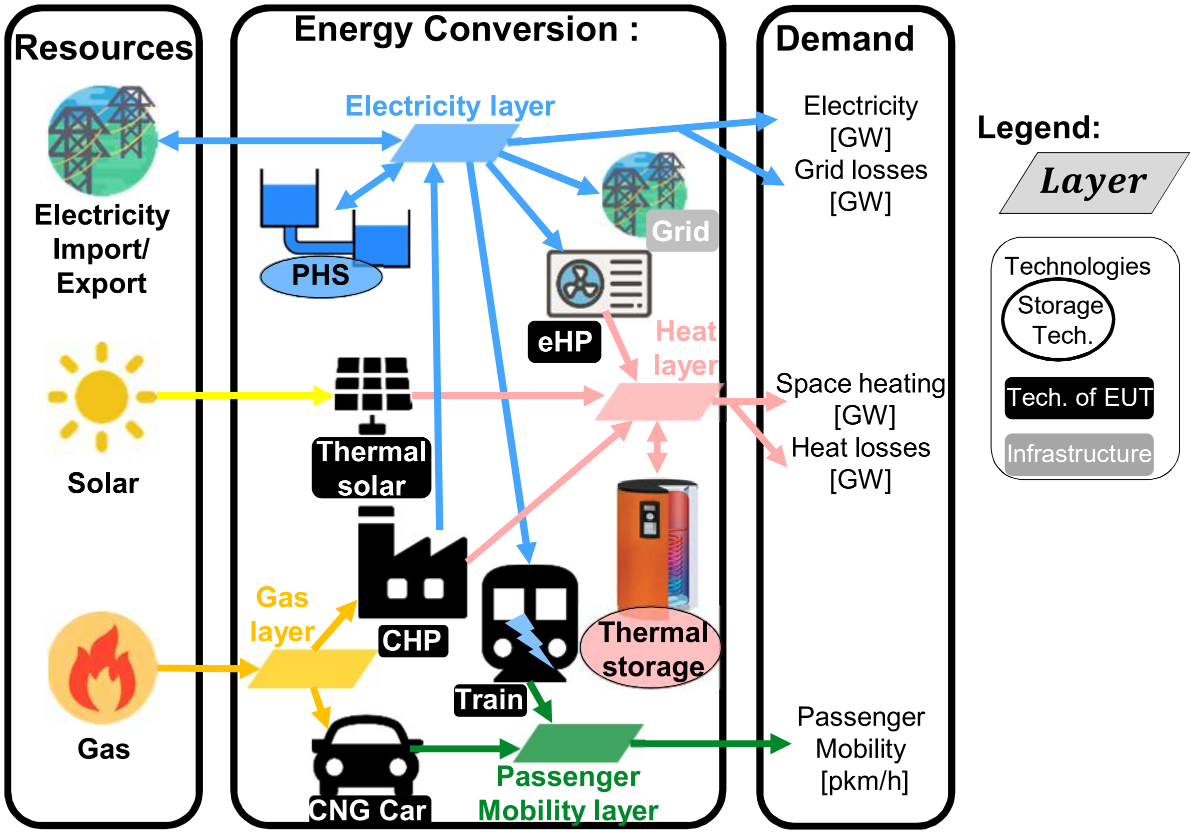


Figure 1: Conceptual example of an energy system with 3 resources, 8 technologies (of which 2 storage (in colored oval) and 1 infrastructure (grey rectangle)) and 4 end use demand (of which 1 losses). Abbreviations: pumped hydro storage (PHS), electrical heat pump (eHP), combined heat and power (CHP), compressed natural gas (CNG). Some icons from [5].

as non-energy the following materials: "*chemical feed-stocks, lubricants and asphalt for road construction.*" [4].

A simplified conceptual example of the energy system structure is proposed in Figure 1. The system is split in three parts: resources, energy conversion and demand. In this illustrative example, resources are solar energy, electricity and NG. The EUD are electricity, space heating and passenger mobility. The energy system encompasses all the energy conversion technologies needed to transform resources and supply EUD. In this example, Solar and NG resources cannot be directly used to supply heat. Thus, they use technologies, such as boilers or combined heat and power (CHP) for NG, to supply the EUT layer (e.g. the high temperature industrial heat layer). *Layers* are defined as all the elements in the system that need to be balanced in each time period; they include resources and EUTs. As an example, the electricity layer must be balanced at any time, meaning that the production and storage must equal the consumption and losses. These layers are connected to each other by *technologies*. We define three types of technologies: *technologies of end-use type*, *storage technologies* and *infrastructure technologies*. A technology of end-use type can convert the energy (e.g. a fuel resource) from one layer to a EUT layer, such as a CHP unit that converts NG into heat and electricity. A storage technology converts energy from a layer to the same one, such as thermal storage (TS) that stores heat to provide heat. In this example, there are two storage technologies: thermal storage for heat and pumped hydro storage (PHS) for electricity. An infrastructure technology gathers the remaining technologies, including the networks, such as the power grid and district heating networks (DHNs), but also technologies linking non end-use layers, such as methane production from wood gasification or hydrogen production from methane reforming.

As an illustrative example of the concept of *layer*, Figure 2 gives a perspective of the electricity layer which is the most complex one, since the electrification of other sectors is foreseen as a key of the energy transition [6]. In the proposed version, 38 technologies are related to the electricity layer. 13 technologies produce exclusively electricity, such as natural gas combined cycle (CCGT), photovoltaic (PV) or wind. 10 combined heat and power (CHP) produce heat and electricity, such as industrial waste CHP. 1 infrastructure represents the grid. 5 storage technologies are implemented, such as PHS, hydro dams, batteries or vehicle-to-grid (V2G). The rest are consumers regrouped in the electrification of heat and mobility. Electrification of the heating sector is supported by direct electric heating but also by the more expensive but more efficient electrical heat pumps for low temperature heat demand. All the data for technologies and resources are reported in detail in Appendix 2. Electrification of mobility is achieved via electric public transportation (train, trolley, metro and electrical/hybrid buses), electric private transportation with the promising vehicle-to-grid (V2G) and hydrogen cars[3] and trains for freight.

1.2 Sets, parameters and variables

Figure 3 gives a visual representation of the sets with their relative indices used throughout the paper.

In order to solve a yearly problem over 8760h, we define the sets $H\_OF\_T(t)$, $TD\_OF\_T(t)$ and $T\_H\_TD(t)$ that give respectively, the hour (h), the typical day (td) or both (h,td) based on the period (t). E.g. if January 2 is associated to typical day 1, then $H\_OF\_T(34) = 10$, $TD\_OF\_T(t) = 1$ and $T\_H\_TD(34) = \{h = 10, td = 1\}$.

Tables 1 and 2 list and describe the model parameters. Tables 3 and 4 list and describe the independent and dependent variables, respectively.

Table 1: Time series parameter list with description. Set indices as in Figure 3

Parameter	**Units**	**Description**
$\%_{elec}(h, td)$	[-]	Yearly time series (adding up to 1) of electricity end-uses
$\%_{sh}(h, td)$	[-]	Yearly time series (adding up to 1) of SH end-uses
$\%_{pass}(h, td)$	[-]	Yearly time series (adding up to 1) of passenger mobility end-uses
$\%_{fr}(h, td)$	[-]	Yearly time series (adding up to 1) of freight mobility end-uses
$c_{p,t}(tech, h, td)$	[-]	Period capacity factor (default 1)

[3] Hydrogen can be produced by electrolysers; thus, the energy comes from electricity.

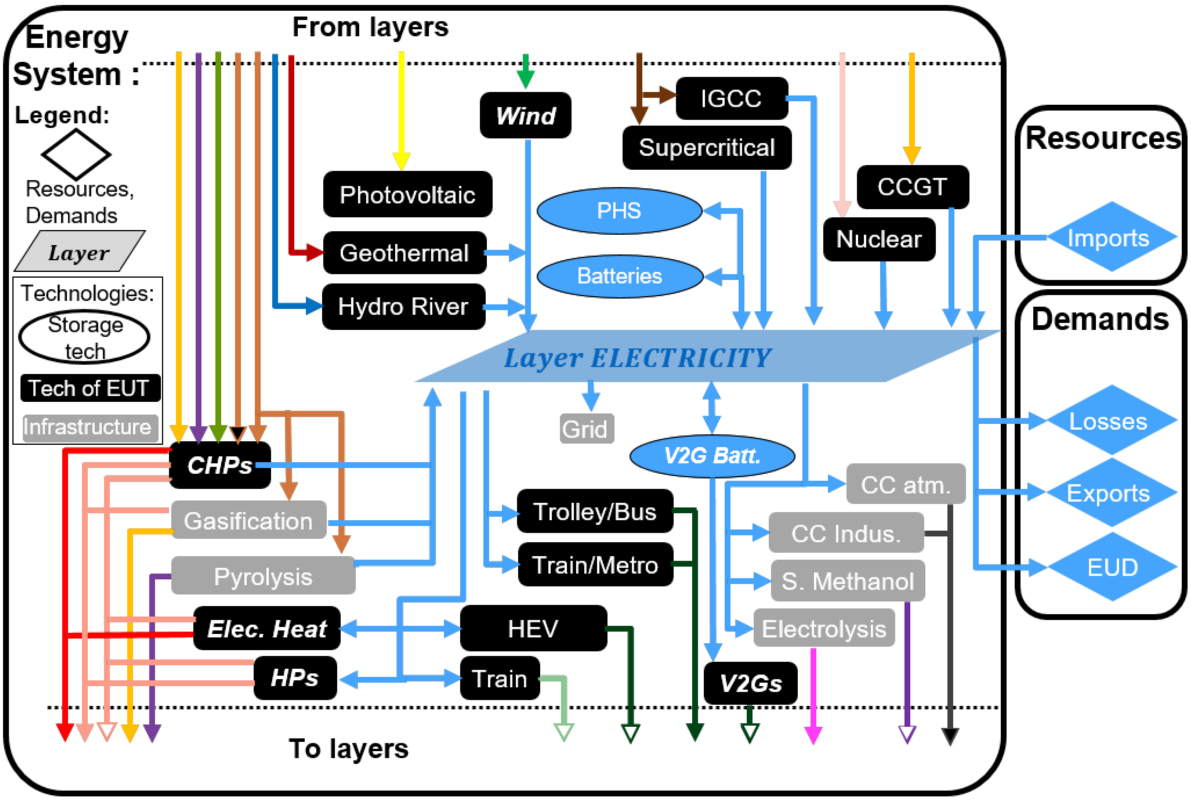


Figure 2: Representation of the Elec layer with all the technologies implemented in EnergyScope Typical Days. ***Bold Italic technologies*** represent a group of different technologies. Refer to Figure 2 of the main paper for color legend. Abbreviations: atmospheric (atm.), Carbon capture (CC), natural gas combined cycle (CCGT), combined heat and power (CHP), heat pump (HP), industrial (ind.) integrated gasification natural gas combined cycle (IGCC), pumped hydro storage (PHS), synthetic methanolation (S. Methanol.), vehicle-to-grid (V2G), end-use demand (EUD).

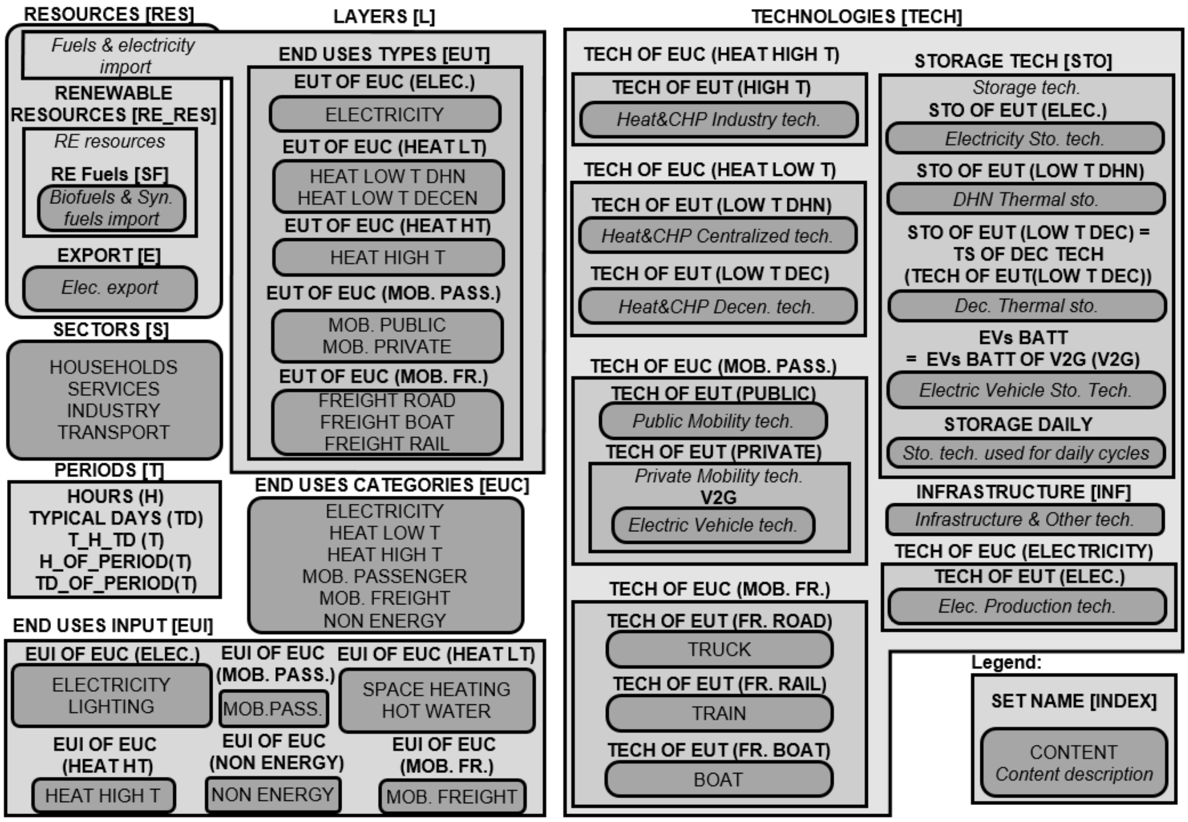


Figure 3: Visual representation of the sets and indices of the LP framework. Abbreviations: space heating (SH), hot water (HW), temperature (T), mobility (MOB), passenger (*Pass.*), vehicle-to-grid (V2G), thermal storage (TS).

Table 2: Scenario parameter list with description. Set indices as in Figure 3

Parameter	Units	Description
$\tau(tech)$	[-]	Investment cost annualization factor
i_{rate}	[-]	Real discount rate
$endUses_{year}(eui, s)$	[GWh/y][a]	Annual end-uses in energy services per sector
$endUsesInput(eui)$	[GWh/y][a]	Total annual end-uses in energy services
re_{share}	[-]	minimum share [0;1] of primary RE
gwp_{limit}	[ktCO$_{2\text{-eq}}$/y]	Higher CO$_{2\text{-eq}}$ emissions limit
$\%_{public,min}$, $\%_{public,max}$	[-]	Lower and upper limit to $\%_{\mathbf{Public}}$
$\%_{fr,rail,min}$, $\%_{fr,rail,max}$	[-]	Lower and upper limit to $\%_{\mathbf{Fr,Rail}}$
$\%_{fr,boat,min}$, $\%_{fr,boat,max}$	[-]	Lower and upper limit to $\%_{\mathbf{Fr,Boat}}$
$\%_{fr,truck,min}$, $\%_{fr,truck,max}$	[-]	Lower and upper limit to $\%_{\mathbf{Fr,Truck}}$
$\%_{dhn,min}$, $\%_{dhn,max}$	[-]	Lower and upper limit to $\%_{\mathbf{DHN}}$
$t_{op}(h, td)$	[h]	Time periods duration (default 1h)
f_{min}, $f_{max}(tech)$	[GW][ab]	Min./max. installed size of the technology
$f_{min,\%}$, $f_{max,\%}(tech)$	[-]	Min./max. relative share of a technology in a layer
$avail(res)$	[GWh/y]	Resource yearly total availability
$c_{op}(res)$	[MCHF/GWh]	Specific cost of resources
$n_{car,max}$	[-]	Maximum number of cars
$\%_{Peak_{sh}}$	[-]	Ratio peak/max. space heating demand in typical days
$f(res \cup tech \setminus sto, l)$	[GW][c]	Input from (< 0) or output to (> 0) layers. $f(i, j) = 1$ if j is main output layer for technology/resource i
$c_{inv}(tech)$	[MCHF/GW][cb]	Technology specific investment cost
$c_{maint}(tech)$	[MCHF/GW/y][cb]	Technology specific yearly maintenance cost
$lifetime(tech)$	[y]	Technology lifetime
$gwp_{constr}(tech)$	[ktCO$_2$-eq./GW][ab]	Technology construction specific GHG emissions
$gwp_{op}(res)$	[ktCO$_2$-eq./GWh]	Specific GHG emissions of resources
$c_p(tech)$	[-]	Yearly capacity factor
$\eta_{sto,in}$, $\eta_{sto,out}(sto, l)$	[-]	Efficiency $[0; 1]$ of storage input from/output to layer. Set to 0 if storage not related to layer.
$\%_{sto_{loss}}(sto)$	[1/h]	Losses in storage (self discharge)
$t_{sto_{in}}(sto)$	[-]	Time to charge storage (Energy to power ratio)
$t_{sto_{out}}(sto)$	[-]	Time to charge storage (Energy to power ratio)
$\%_{sto_{avail}}(sto)$	[-]	Storage technology availability to charge/discharge
$\%_{net_{loss}}(eut)$	[-]	Losses coefficient $[0; 1]$ in the networks (grid and DHN)
$ev_{Batt,size}(v2g)$	[GWh]	Battery size per V2G car technology
$c_{grid,extra}$	[MCHF]	Cost to reinforce the grid due to IRE penetration
$elec_{import,max}$	[GW]	Maximum interconnections capacity
$solar_{area}$	[km^2]	Available area for solar panels

[a][Mpkm] (millions of passenger-km) for passenger, [Mtkm] (millions of ton-km) for freight mobility end-uses
[b][GWh] if $tech \in STO$
[c][Mpkm/h] for passenger, [Mtkm/h] for freight mobility end-uses

Table 3: Independent variable list with description. All variables are continuous and non-negative, unless otherwise indicated.

Variable	Units	Description
$\%_{\mathbf{Public}}$	[-]	Ratio $[0;1]$ public mobility over total passenger mobility
$\%_{\mathbf{Fr,Rail}}$	[-]	Ratio $[0;1]$ rail transport over total freight transport
$\%_{\mathbf{Fr,Boat}}$	[-]	Ratio $[0;1]$ boat transport over total freight transport
$\%_{\mathbf{Fr,Truck}}$	[-]	Ratio $[0;1]$ truck transport over total freight transport
$\%_{\mathbf{DHN}}$	[-]	Ratio $[0;1]$ centralized over total low-temperature heat
$\mathbf{F}(tech)$	$[\mathrm{GW}]^{ab}$	Installed capacity with respect to main output
$\mathbf{F_t}(tech \cup res, h, td)$	$[\mathrm{GW}]^{ab}$	Operation in each period
$\mathbf{Sto_{in}}, \mathbf{Sto_{out}}(sto, l, h, td)$	[GW]	Input to/output from storage units
$\mathbf{P_{Nuc}}$	[GW]	Constant load of nuclear
$\%_{\mathbf{MobPass}}(\mathit{TECH\ OF\ EUC(MobPass)})$	[-]	Constant share of passengers mobility
$\%_{\mathbf{MobFreight}}(\mathit{TECH\ OF\ EUC(MobFreight)})$	[-]	Constant share of freight mobility
$\%_{\mathbf{HeatDec}}(\mathit{TECH\ OF\ EUT(}(\mathit{HeatLowTDEC})\backslash\{\mathrm{Dec_{Solar}}\})$	[-]	Constant share of Heat low T decentralised supplied by a technology plus its associated thermal solar and storage
$\mathbf{F_{sol}}(\mathit{TECH\ OF\ EUT(}(\mathit{HeatLowTDEC})\backslash\{\mathrm{Dec_{Solar}}\})$	[GW]	Solar thermal installed capacity associated to a decentralised heating technology
$\mathbf{F_{t_{sol}}}(\mathit{TECH\ OF\ EUT(}(\mathit{HeatLowTDEC})\backslash\{\mathrm{Dec_{Solar}}\})$	[GW]	Solar thermal operation in each period

[a] [Mpkm] (millions of passenger-km) for passenger, [Mtkm] (millions of ton-km) for freight mobility end-uses
[b] [GWh] if $tech \in STO$

Table 4: Dependent variable list with description. All variables are continuous and non-negative, unless otherwise indicated.

Variable	Units	Description
$\mathbf{EndUses}(l, h, td)$	$[\mathrm{GW}]^{a}$	End-uses demand. Set to 0 if $l \notin EUT$
$\mathbf{C_{tot}}$	[MCHF/y]	Total annual cost of the energy system
$\mathbf{C_{inv}}(tech)$	[MCHF]	Technology total investment cost
$\mathbf{C_{maint}}(tech)$	[MCHF/y]	Technology yearly maintenance cost
$\mathbf{C_{op}}(res)$	[MCHF/y]	Total cost of resources
$\mathbf{GWP_{tot}}$	[ktCO$_2$-eq./y]	Total yearly GHG emlissions of the energy system
$\mathbf{GWP_{constr}}(tech)$	[ktCO$_2$-eq.]	Technology construction GHG emissions
$\mathbf{GWP_{op}}(res)$	[ktCO$_2$-eq./y]	Total GHG emissions of resources
$\mathbf{Net_{loss}}(eut, h, td)$	[GW]	Losses in the networks (grid and DHN)
$\mathbf{Sto_{level}}(sto, t)$	[GWh]	Energy stored over the year

[a] [Mpkm] (millions of passenger-km) for passenger, [Mtkm] (millions of ton-km) for freight mobility end-uses

1.3 Linear Programming model formulation

The energy system is formulated as a linear programming (LP) problem. It optimises the design by computing the installed capacity of each technology, as well as the operation in each period, to meet the energy demand and minimize the total annual cost of the system. In the following, we present the complete formulation of the model. It accounts for sets, parameters, variables, constraints and the objective function. The model formulation is expressed by the equations in Figure 4 and Eqs. (1)-(37).

End-use demand

We use the end-use demand (EUD) instead of the final energy consumption (FEC) to characterise the demand. According to the definition of the European commission, FEC is defined as "*the energy which reaches the final consumer's door*" [2]. In other words, the FEC is the amount of input fuel needed to satisfy the EUD in energy services. As an example, in the case of decentralized heat production with a gas boiler, the FEC is the amount of NG consumed by the boiler; the EUD is the amount of heat produced by the boiler, i.e. the heating service needed by the final user. This modelling choice has two advantages. First, it introduces a clear distinction between demand and supply. On the one hand, the demand concerns the definition of the end-uses, i.e. the requirements in energy services (e.g. the mobility needs). On the other hand, the supply concerns the choice of the energy conversion technologies to supply these services (e.g. the types of vehicles used to satisfy the mobility needs). Based on the technology choice, the same EUD can be satisfied with different FEC, depending on the efficiency of the chosen energy conversion technology. Second, it facilitates the inclusion in the model of electric technologies for heating and transportation.
The hourly end-use demand (**EndUses**) is computed based on the yearly end-use demand (*endUsesInput*), distributed according to a normalised time series.

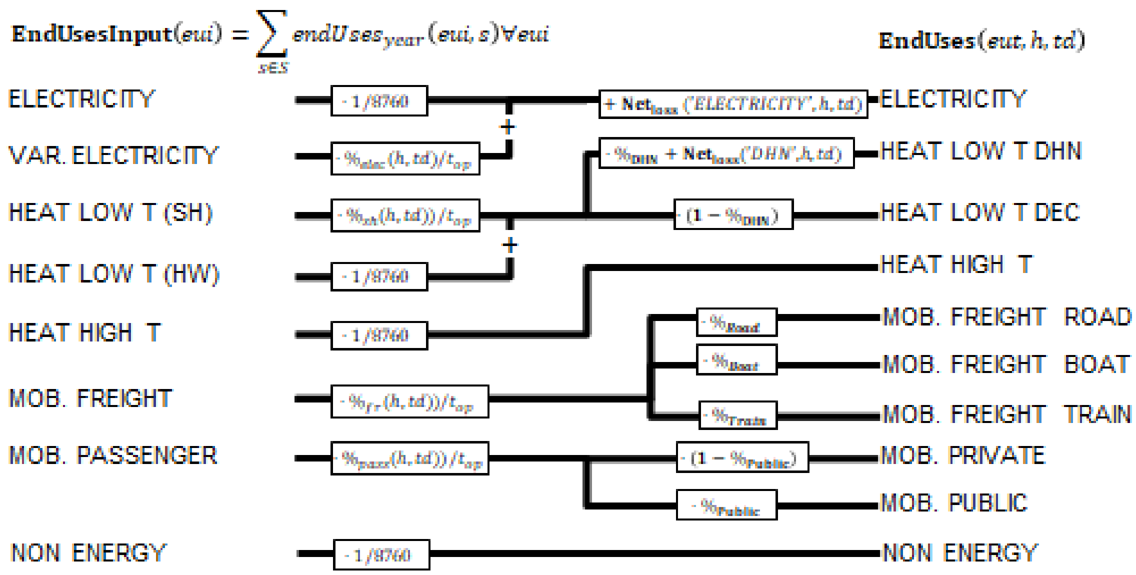


Figure 4: **EndUses** calculation starting from yearly demand model inputs (*endUsesInput*). Adapted from [7]. Abbreviations: space heating (sh), district heating network (DHN), hot water (HW), passenger (pass) and freight (fr).

Figure 4 graphically presents the constraints associated to the hourly end use demand (**EndUses**), e.g. the public mobility demand at time t is equal to the hourly passenger mobility demand times the public mobility share ($\mathbf{\%_{Public}}$).

Electricity end-uses result from the sum of the electricity-only demand, assumed constant throughout the year, and the variable demand of electricity, distributed across the periods according to $\%_{elec}$. Low-temperature heat demand results from the sum of the yearly demand for hot water (HW), evenly shared across the year, and space heating (SH), distributed across the periods according to $\%_{sh}$.

The percentage repartition between centralized (DHN) and decentralized heat demand is defined by the variable $\mathbf{\%_{DHN}}$. High temperature process heat and mobility demand are evenly distributed across the periods. Passenger mobility demand is expressed in passenger-kilometers (pkms), freight transportation demand is in ton-kilometers (tkms). The variables $\mathbf{\%_{Public}}$ and $\mathbf{\%_{Rail}}$ define the penetration of public transportation in passenger mobility and of train in freight, respectively.

Cost, emissions and objective function

The objective Eq. (1) is the minimisation of the total annual cost of the energy system ($\mathbf{C_{tot}}$), defined as the sum of the annualized investment cost of technologies (τ $\mathbf{C_{inv}}$), the operating and maintenance cost of technologies ($\mathbf{C_{maint}}$) and the operating cost of the resources ($\mathbf{C_{op}}$). The total investment cost ($\mathbf{C_{inv}}$) of each technology results from the multiplication of its specific investment cost (c_{inv}) and its installed size ($\mathbf{F}$), the latter defined with respect to the main end-uses output type Eq. (3). $\mathbf{C_{inv}}$ is annualised with the factor τ, calculated based on the interest rate (i_{rate}) and the technology lifetime (*lifetime*) Eq. (2). The total operation and maintenance cost is calculated in the same way Eq. (4). The total cost of the resources is calculated as the sum of the end-use over different periods multiplied by the period duration (t_{op}) and the specific cost of the resource (c_{op}) Eq. (5). Note that, in Eq. (5), summing over the typical days using the set T_H_TD is equivalent to summing over the 8760h of the year.

$$\min \ \mathbf{C_{tot}} = \sum_{j \in TECH} \Big(\tau(j)\mathbf{C_{inv}}(j) + \mathbf{C_{maint}}(j) \Big) + \sum_{i \in RES} \mathbf{C_{op}}(i) \tag{1}$$

$$\text{s.t. } \tau(j) = \frac{i_{rate}(i_{rate}+1)^{lifetime(j)}}{(i_{rate}+1)^{lifetime(j)} - 1} \qquad \forall j \in TECH \tag{2}$$

$$\mathbf{C_{inv}}(j) = c_{inv}(j)\mathbf{F}(j) \qquad \forall j \in TECH \tag{3}$$

$$\mathbf{C_{maint}}(j) = c_{maint}(j)\mathbf{F}(j) \qquad \forall j \in TECH \tag{4}$$

$$\mathbf{C_{op}}(i) = \sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} c_{op}(i)\mathbf{F_t}(i,h,td)t_{op}(h,td) \qquad \forall i \in RES \tag{5}$$

The global annual greenhouse gas (GHG) emissions are calculated using a life cycle assessment (LCA) approach, i.e. taking into account emissions of technologies and resources "from cradle to grave". For climate change, the natural choice as indicator is the global warming potential (GWP), expressed in ktCO_2-eq./year. In Eq. (6), the total yearly emissions of the system ($\mathbf{GWP_{tot}}$) are defined as the sum of the emissions related to the construction and end-of-life of the energy conversion technologies ($\mathbf{GWP_{constr}}$), allocated to one year based on the technology lifetime (*lifetime*), and the emissions related to resources ($\mathbf{GWP_{op}}$). Similarly to the costs, the total emissions related to the construction of technologies are the product of the specific emissions (gwp_{constr}) and the installed size ($\mathbf{F}$), Eq. (7). The total emissions of resources are the emissions associated to fuels (from cradle to combustion) and imports of electricity (gwp_{op}) multiplied by the period duration (t_{op}) (Eq 8) [4] . In this paper, the metric has been simplified by removing the emissions related to the construction and end-of-life of the energy conversion technologies (gwp_{constr}). We motivate this metric as it is the one used in official agencies, such as the European Union Commission (EUC) or International Energy Agency (IEA). The new formulation is proposed in Eq. (6).

$$\mathbf{GWP_{tot}} = \sum_{j \in TECH} \frac{\mathbf{GWP_{constr}}(j)}{lifetime(j)} + \sum_{i \in RES} \mathbf{GWP_{op}}(i)$$

$$\left(\text{in this paper : } \mathbf{GWP_{tot}} = \sum_{i \in RES} \mathbf{GWP_{op}}(i) \right) \tag{6}$$

$$\mathbf{GWP_{constr}}(j) = gwp_{constr}(j)\mathbf{F}(j) \qquad \forall j \in TECH \tag{7}$$

$$\mathbf{GWP_{op}}(i) = \sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} gwp_{op}(i)\mathbf{F_t}(i,h,td)t_{op}(h,td) \qquad \forall i \in RES \tag{8}$$

System design and operation

The installed capacity of technologies ($\mathbf{F}$) is constrained between upper and lower bounds (f_{max} and f_{min}), Eq. (9). This formulation allows accounting for old technologies still existing in the target year (lower bound), but also for the maximum deployment potential of a technology. As an example, for hydroelectric power plants, f_{min} represents the existing installed capacity (which will still be available in the future), while f_{max} represents the maximum potential .

$$f_{min}(j) \leq \mathbf{F}(j) \leq f_{max}(j) \qquad \forall j \in TECH \tag{9}$$

The operation of resources and technologies in each period is determined by the decision variable $\mathbf{F_t}$. The capacity factor of technologies is conceptually divided into two components: a capacity factor for each period ($c_{p,t}$) depending on resource availability (e.g. renewables) and a yearly capacity factor (c_p) accounting for technology downtime and maintenance. For a given technology, the definition of only one of these two is needed, the other one being fixed to the default value of 1. Eqs. (10) and (11) link the installed size of a technology to its actual use in each period (F_t) via the two capacity factors. The total use of resources is limited by the yearly availability ($avail$), Eq. (12).

$$\mathbf{F_t}(j,h,td) \leq \mathbf{F}(j)c_{p,t}(j,h,td) \qquad \forall j \in TECH, \forall h \in H, \forall td \in TD \tag{10}$$

$$\sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j,h,td)t_{op}(h,td) \leq \mathbf{F}(j)c_p(j) \sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} t_{op}(h,td) \qquad \forall j \in TECH \tag{11}$$

$$\sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(i,h,td)t_{op}(h,td) \leq avail(i) \qquad \forall i \in RES \tag{12}$$

The matrix f defines for all technologies and resources outputs to (positive) and inputs (negative) layers. Eq. (13) expresses the balance for each layer: all outputs from resources and technologies (including storage) are used to satisfy the EUD or as inputs to other resources and

[4] To simplify the reading, we write in this paper $t \in T|\{h,td\} \in T\_H\_TD(t)$. However, this cannot be directly implemented in the code and it requires two additional sets : $HOUR\_OF\_PERIOD(t)$ and $TYPICAL\_DAY\_OF\_PERIOD(t)$. Hence, in the paper we have: $t \in T|\{h,td\} \in T\_H\_TD(t)$, which is equivalent in the code to $t \in T|h \in HOUR\_OF\_PERIOD(t), td \in TYPICAL\_DAY\_OF\_PERIOD(t)$.

technologies.

$$\sum_{i \in RES \cup TECH \setminus STO} f(i,l)\mathbf{F_t}(i,h,td) + \sum_{j \in STO} \Big(\mathbf{Sto_{out}}(j,l,h,td) - \mathbf{Sto_{in}}(j,l,h,td) \Big) - \mathbf{EndUses}(l,h,td) = 0$$
$$\forall l \in L, \forall h \in H, \forall td \in TD \quad (13)$$

Storage

The storage level ($\mathbf{Sto_{level}}$) at a time step (t) is equal to the storage level at $t-1$ (accounting for the losses in $t-1$), plus the inputs to the storage, minus the output from the storage (accounting for input/output efficiencies (14)). The storage systems which can only be used for short-term (daily) applications are included in the STO DAILY set. For these units, Eq. (15) imposes that the storage level be the same at the end of each typical day. Adding this constraint drastically reduces the computational time. For the other storage technologies, which can also be used for seasonal storage, the capacity is bounded by Eq (16). For these units, the storage behaviour is thus optimized over 8760h, as explained in the methodology Section of the paper.

$$\mathbf{Sto_{level}}(j,t) = \mathbf{Sto_{level}}(j,t-1) \cdot (1 - \%_{sto_{loss}}(j)) +$$
$$t_{op}(h,td) \cdot \Big(\sum_{l \in L | \eta_{sto,in}(j,l) > 0} \mathbf{Sto_{in}}(j,l,h,td) \eta_{sto,in}(j,l) - \sum_{l \in L | \eta_{sto,out}(j,l) > 0} \mathbf{Sto_{out}}(j,l,h,td) / \eta_{sto,out}(j,l) \Big)$$
$$\forall j \in STO, \forall t \in T | \{h,td\} \in T\_H\_TD(t) \quad (14)$$

$$\mathbf{Sto_{level}}(j,t) = \mathbf{F_t}(j,h,td) \qquad \forall j \in STO\ DAILY, \forall t \in T | \{h,td\} \in T\_H\_TD(t) \quad (15)$$

$$\mathbf{Sto_{level}}(j,t) \leq \mathbf{F}(j) \qquad \forall j \in STO \setminus STO\ DAILY, \forall t \in T \quad (16)$$

Eqs. (17)-(18) force the power input and output to zero if the layer is incompatible [5]. As an example, a PHS will only be linked to the electricity layer (input/output efficiencies > 0). All other efficiencies will be equal to 0, to impede that the PHS exchanges with incompatible layers (e.g. mobility, heat, etc). Eq. (19) limits the power input/output of a storage technology based on its installed capacity ($\mathbf{F}$) and three specific characteristics. First, storage availability ($\%_{sto_{avail}}$) is defined as the ratio between the available storage capacity and the total installed capacity (default value is 1). This parameter is required to realistically represent V2G, for which we assume that only a fraction of the fleet can charge/discharge at the same time. Second and third, the charging/discharging time ($t_{sto_{in}}$, $t_{sto_{out}}$), which are the time to complete a full charge/discharge from empty/full storage[6]. As an example, a daily thermal storage can be fully discharged in minimum 4 hours ($t_{sto_{out}} = 4$[h]), and fully charged in maximum 4 hours ($t_{sto_{in}} = 4$[h]).

$$\mathbf{Sto_{in}}(j,l,h,td) \cdot \Big(\lceil \eta_{sto,in}(j,l) \rceil - 1 \Big) = 0 \qquad \forall j \in STO, \forall l \in L, \forall h \in H, \forall td \in TD \quad (17)$$

$$\mathbf{Sto_{out}}(j,l,h,td) \cdot \Big(\lceil \eta_{sto,out}(j,l) \rceil - 1 \Big) = 0 \qquad \forall j \in STO, \forall l \in L, \forall h \in H, \forall td \in TD \quad (18)$$

[5] In the code, these equations are implemented with a *if-then* statement.

[6] In this linear formulation, storage technologies can charge and discharge at the same time. On the one hand, this avoids the need of integer variables (see 1.3.2); on the other hand, it has no physical meaning. However, in a cost minimization problem, the cheapest solution identified by the solver will always choose to either charge or discharge at any given t, as long as cost and efficiencies are defined. Hence, we recommend to always verify numerically the fact that only storage inputs or outputs are activated at each t, as we do in all our implementations.

$$\Big(\mathbf{Sto_{in}}(j,l,h,td)t_{sto_{in}}(j)+\mathbf{Sto_{out}}(j,l,h,td)t_{sto_{out}}(j)\Big)\leq\mathbf{F}(j)\%_{sto_{avail}}(j)$$
$$\forall j\in STO,\forall l\in L,\forall h\in H,\forall td\in TD \quad (19)$$

Infrastructure

Eq. (20) calculates network losses as a share ($\%_{net_{loss}}$) of the total energy transferred through the network. As an example, losses in the electricity grid are estimated to be 4.5% of the energy transferred[7]. Eqs. (21)-(22) define the extra investment for networks. Integration of intermittent renewable energies (iRE) implies an additional investment costs for the electricity grid ($c_{grid,extra}$). As an example, the needed investments are expected to be 15.2 billions €$_{2015}$ (see part 2.2.3 for more information). Eq. (22) links the size of DHN to the total size of the installed centralized energy conversion technologies.

$$\mathbf{Net_{loss}}(eut,h,td)=\Big(\sum_{i\in RES\cup TECH\setminus STO|f(i,eut)>0}f(i,eut)\mathbf{F_t}(i,h,td)\Big)\%_{net_{loss}}(eut)$$
$$\forall eut=EUT,\forall h\in H,\forall td\in TD \quad (20)$$

$$\mathbf{F}(Grid)=\frac{c_{grid,extra}}{c_{inv}(Grid)}\frac{\mathbf{F}(Wind_{onshore})+\mathbf{F}(Wind_{offshore})+\mathbf{F}(PV)}{f_{max}(Wind_{onshore})+f_{max}(Wind_{offshore})+f_{max}(PV)} \quad (21)$$

$$\mathbf{F}(DHN)=\sum_{j\in TECH\ OF\ EUT(HeatLowTDHN)}\mathbf{F}(j) \quad (22)$$

Additional Constraints

Nuclear power plants are assumed to have no power variation over the year (23). If needed, this equation can be replicated for all other technologies for which a constant operation over the year is desired.

$$\mathbf{F_t}(Nuclear,h,td)=\mathbf{P_{Nuc}} \qquad \forall h\in H,\forall td\in TD \quad (23)$$

Eqs. (24)-(25) impose that the share of the different technologies for mobility ($\mathbf{\%_{MobPass}}$) and ($\mathbf{\%_{Freight}}$) be the same at each time step[8]. In other words, if 20% of the mobility is supplied by train, this share remains constant in the morning or the afternoon. The addition of this constraint is motivated by the fact that the investment cost of passenger and freight transport technologies is not accounted for in the model ($c_{inv}=0$ for these technologies). Eq. 26 verifies that the freight technologies supply the overall freight demand (this constraint is related to Figure 4).

$$\mathbf{F_t}(j,h,td)=\mathbf{\%_{MobPass}}(j)\sum_{l\in EUT\ of\ EUC(MobPass)}\mathbf{EndUses}(l,h,td)$$
$$\forall j\in\ TECH\ OF\ EUC(MobPass),\forall h\in H,\forall td\in TD \quad (24)$$

$$\mathbf{F_t}(j,h,td)=\mathbf{\%_{MobFreight}}(j)\sum_{l\in EUT\ of\ EUC(MobFreight)}\mathbf{EndUses}(l,h,td)$$

[7] This is the ratio between the losses in the grid and the total annual electricity production in Belgium in 2015 (c.f. 2.9).

[8] All equations expressed in a compact non-linear form in this section 24, 25, 29 and 33) can be linearized; their linearization is given in Appendix 1.3.2

$$\forall j \in \textit{TECH OF EUC}(\textit{MobFreight}), \forall h \in H, \forall td \in TD \quad (25)$$

$$1 = \mathbf{\%_{Fr,Rail}} + \mathbf{\%_{Fr,Train}} + \mathbf{\%_{Fr,Boat}} \quad (26)$$

Decentralised heat production:

Thermal solar is implemented as a decentralized technology. It is always installed together with another decentralized technology, which serves as backup to compensate for the intermittency of solar thermal. Thus, we define the total installed capacity of solar thermal $\mathbf{F}(Dec_{Solar})$ as the sum of $\mathbf{F_{sol}}(j)$ (28), where $\mathbf{F_{sol}}(j)$ is the solar thermal capacity associated to the backup technology *j*. Eq. (27) links the installed size of each solar thermal capacity ($\mathbf{F_{sol}}(j)$) to its actual production ($\mathbf{F_{t_{sol}}}(j,h,td)$) via the solar capacity factor ($c_{p,t}(Dec_{Solar},h,td)$).

$$\mathbf{F_{t_{sol}}}(j,h,td) \leq \mathbf{F_{sol}}(j) c_{p,t}(Dec_{Solar},h,td)$$
$$\forall j \in \textit{TECH OF EUT}(\textit{HeatLowTDec}) \setminus \{Dec_{Solar}\}, \forall h \in H, \forall td \in TD \quad (27)$$

$$\mathbf{F}(Dec_{Solar}) = \sum_{j \in \textit{TECH OF EUT}(\textit{HeatLowTDec}) \setminus \{Dec_{Solar}\}} \mathbf{F_{sol}}(j) \quad (28)$$

A thermal storage *i* is defined for each decentralised heating technology *j*, to which it is related via the set *TS OF DEC TECH*, i.e. *i=TS OF DEC TECH(j)*. Each thermal storage *i* can store heat from its technology *j* and the associated thermal solar $\mathbf{F_{sol}}(j)$. Similarly to the passenger mobility, Eq. (29) makes the model more realistic by defining the operating strategy for decentralized heating. In fact, in the model we represent decentralized heat in an aggregated form; however, in a real case, residential heat cannot be aggregated obviously. A house heated by a decentralised gas boiler and solar thermal panels should not be able to be heated by the electrical heat pump and thermal storage of the neighbours, and vice-versa. Hence, Eq. (29) imposes that the use of each technology ($\mathbf{F_t}(j,h,td)$), plus its associated thermal solar ($\mathbf{F_{t_{sol}}}(j,h,td)$) plus its associated storage outputs ($\mathbf{Sto_{out}}(i,l,h,td)$) minus its associated storage inputs ($\mathbf{Sto_{in}}(i,l,h,td)$) should be a constant share ($\mathbf{\%_{HeatDec}}(j)$) of the decentralised heat demand ($\mathbf{EndUses}(HeatLowT,h,td)$). Figure 5 shows, through an example with two technologies (a gas boiler and a heat pump (HP)), how decentralised thermal storage and thermal solar are implemented.

$$\mathbf{F_t}(j,h,td) + \mathbf{F_{t_{sol}}}(j,h,td) + \sum_{l \in L} \Big(\mathbf{Sto_{out}}(i,l,h,td) - \mathbf{Sto_{in}}(i,l,h,td)\Big)$$
$$= \mathbf{\%_{HeatDec}}(j)\mathbf{EndUses}(HeatLowT,h,td)$$
$$\forall j \in \textit{TECH OF EUT}(\textit{HeatLowTDec}) \setminus \{Dec_{Solar}\}, i \in \textit{TS OF DEC TECH}(j), \forall h \in H, \forall td \in TD \quad (29)$$

Vehicle-to-grid:

Vehicle-to-grid dynamics are included in the model via the *V2G* set. For each vehicle $j \in$ *V2G*, a battery i ($i \in$ *EVs_BATT*) is associated using the set *EVs_BATT OF V2G* ($i \in$ *EVs_BATT OF V2G*(*j*)). Each type *j* of *V2G* has a different size of battery per car ($ev_{Batt,size}(j)$), e.g. the first generation battery of the Nissan Leaf (ZE0) has a capacity of 24 kWh[9]. To estimate the number of vehicles of a given technology, we use the share of mobility covered supplied

[9]from `https://en.wikipedia.org/wiki/Nissan_Leaf`, consulted on 29-01-2019

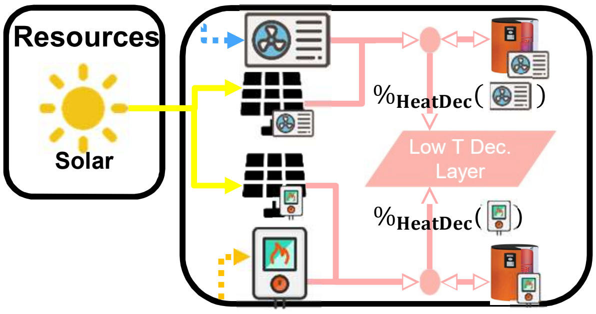


Figure 5: Illustrative example of a decentralised heating layer with thermal storage, solar thermal and two conventional production technologies, gas boilers and electrical HP. In this case, Eq. 29 applied to the electrical HPs becomes the equality between the two following terms: left term is the heat produced by: the eHPs ($\mathbf{F_t}('eHPs')$), the solar panel associated to the eHPs ($\mathbf{F_{t_{sol}}}('eHPs')$) and the storage associated to the eHPs; right term is the product between the share of decentralised heat supplied by eHPs ($\%_{\mathbf{HeatDec}}$(*'eHPs'*)) and heat low temperature decentralised demand ($\mathbf{EndUses}(HeatLowT, h, td)$).

by this technology ($\%_{\mathbf{MobPass}}$) and the number of cars required if all the mobility was covered with private cars $n_{car,max}$[10]. Thus, the energy that can be stored in batteries $\mathbf{F}(i)$ of $V2G(j)$ is the product of the maximum number of cars ($n_{car,max}$) mutliplied by the share of the mobility covered by the type of vehicle j ($\%_{\boldsymbol{MobPass}}(j)$) and the size of battery per car ($ev_{Batt,size}(j)$) (30). As an example, if all the drivers of Belgium (6.55 millions) owned a car and 5% of the mobility was supplied by Nissan Leaf (ZE0), then the energy that could be stored by this technology would be 7.63 GWh.

Eq. (31) forces batteries of electric vehicle to supply, at least, the energy required by each associated electric vehicle technology. This lower bound is not an equality; in fact, according to the V2G concept, batteries can also be used to support the grid. Figure 6 shows through an example with only battery electric vehicles (BEVs) how Eq. (31) simplifies the implementation of V2G. In this illustration, a battery technology is associated to a BEV. The battery can either supply the BEV needs or restore electricity to the grid.

$$\mathbf{F}(i) = n_{car,max}\%_{\mathbf{MobPass}}(j)ev_{Batt,size}(j) \qquad \forall j \in V2G, i \in EVs\_BATT\ OF\ V2G(j) \quad (30)$$

$$\mathbf{Sto_{out}}(i, Elec, h, td) \geq -f(j, Elec)\mathbf{F_t}(j, h, td)$$
$$\forall j \in V2G, \forall i \in EVs\_BATT\ OF\ V2G(j), \forall h \in H, td \in TD \quad (31)$$

Peak demand:

Finally, Eqs. (32)-(33) constrain the installed capacity of low temperature heat supply. Based on the selected typical days (TDs), the ratio between the yearly peak demand and the TDs peak demand is defined for space heating ($\%_{Peak_{sh}}$). Eq. (32) imposes that the installed capacity for decentralised technologies covers the real peak over the year. Similarly, Eq. (33) forces the centralised heating system to have a supply capacity (production plus storage) higher than the peak demand.

[10]This parameter is hard to find. However, its value is only used to assess the overall size of electric vehicles (EVs) batteries. These batteries are used for V2G and smart charging. It has been verified that a variation in this value has a almost no impact on the results.

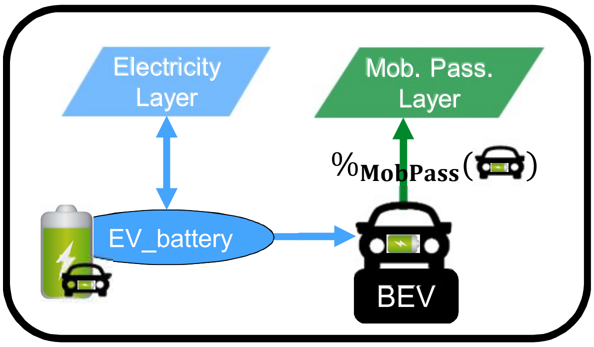


Figure 6: Illustrativee example of a V2G implementation. The battery can interact with the electricity layer. The V2G takes the electricity from the battery to provide a constant share ($\%_{\mathbf{MobPass}}$) of the passenger mobility layer (*Mob. Pass.*).

$$\mathbf{F}(j) \geq \%_{Peak_{sh}} \max_{h\in H, td \in TD} \{\mathbf{F_t}(j,h,td)\}$$
$$\forall j \in \mathit{TECH\ OF\ EUT\ (HeatLowTDEC)} \setminus \{Dec_{Solar}\} \quad (32)$$

$$\sum_{j\in TECH\ OF\ EUT(HeatLowTDHN), i\in STO\ OF\ EUT(HeatLowTDHN)} \Big(\mathbf{F}(j) + \mathbf{F}(i)/t_{sto_{out}}(i, HeatLowTDHN)\Big)$$
$$\geq \%_{Peak_{sh}} \max_{h\in H, td\in TD} \big\{\mathbf{EndUses}(HeatLowTDHN, h, td)\big\} \quad (33)$$

1.3.1 Adaptation for the case study

Additional constraints are required to implement the scenarios. Scenarios require six additional constraints (34-39) to impose a limit on the GWP emissions, the minimum share of renewable energies (RE) primary energy, the relative shares of some technologies, such as gasoline cars in the private mobility, the cost of energy efficiency measures, the electricity import power capacity and the surface area for solar technologies. Eq. 34 imposes a limit on the GWP (gwp_{limit}). Eq. 35 fixes the minimum renewable primary energy share. Eq. 36 is complementary to Eq. 9, as it expresses the minimum ($f_{min,\%}$) and maximum ($f_{max,\%}$) yearly output shares of each technology for each type of EUD. In fact, for a given technology, assigning a relative share (e.g. boilers providing at least a given percent of the total heat demand) is more intuitive and close to the energy planning practice than limiting its installed size. $f_{min,\%}$ and $f_{max,\%}$ are fixed to 0 and 1, respectively, unless otherwise indicated. Eq. 37 imposes the cost of energy efficiency. The EUD is based on a scenario detailed in Section 2.1 and has a lower energy demand than the "business as usual" scenario, which has the highest energy demand. Hence, the energy efficiency cost represents the difference between the implemented scenario and the "business as usual" scenario. As explained later in 2.8.3, the implemented scenario has the lowest EUD, in counterpart, this scenario requires to invest the maximum in efficiency measures. Eq. 38 limits the power grid import capacity from neighbouring countries ($elec_{import,max}$). In this model version, the upper limit for solar based technologies is calculated based on the available land area ($solar_{area}$), Eq. 39. The equivalence between an install capacity (in watt peaks Wp) and the land use (in km^2) is calculated based on the power peak density ([Wp/m^2]). In other words, it represents the peak power of a one square meter solar panel. We evaluate that PV and solar thermal have a power peak density of 0.2367 and 0.2857 [GW/km^2][11]. Thus, the land use of PV is the installed power ($\mathbf{F}(PV)$ in [GW]) divided by the power peak density (in [GW/km^2]). This area is a lower bound of the real installation used. Indeed, here, the calculated area correspond to the installed PV. However, in utility plants, panels are oriented perpendicular to the sunlight. By consequence, a space is required to avoid shadow between rows of panels. In the literature, we define the *ground cover ratio* as the total spatial requirements of large scale solar PV relative to the area of the solar panels. This ratio is 20%, which means that for each square meter PV panel installed, 4 square meters are needed [**Dupont2020**].

$$\mathbf{GWP_{tot}} \leq gwp_{limit} \tag{34}$$

$$\sum_{j \in \text{RES}_{\text{re}}, t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j,h,td) \cdot t_{op}(h,td) \geq re_{\text{share}} \sum_{j \in RES, t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j,h,td) \cdot t_{op}(h,td) \tag{35}$$

$$f_{min,\%}(j) \sum_{j' \in TECH\ OF\ EUT(eut), t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j',h,td) \cdot t_{op}(h,td) \leq \sum_{t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j,h,td) \cdot t_{op}(h,td) \leq f_{max,\%}(j) \sum_{j'' \in TECH\ OF\ EUT(eut), t \in T | \{h,td\} \in T\_H\_TD(t)} \mathbf{F_t}(j'',h,td) \cdot t_{op}(h,td)$$
$$\forall eut \in EUT, \forall j \in TECH\ OF\ EUT(eut) \tag{36}$$

$$\mathbf{F}(Efficiency) = \frac{1}{1 + i_{rate}} \tag{37}$$

$$\mathbf{F_t}(Electricity, h, td)) \leq elec_{import,max} \qquad \forall h \in H, \forall td \in TD \tag{38}$$

$$\mathbf{F}(PV)/0.2367 + (\mathbf{F}(Dec_{Solar}) + \mathbf{F}(DHN_{Solar}))\,/0.2857 \leq solar_{area} \tag{39}$$

1.3.2 Linearisation of integer variables

Equations (24 and 29) multiply two variables among which **EndUses**. The latter is a dependent variable depending only on parameters, and thus it can be rewritten as a sum and products of parameters as shown in Figure 4.

Compared to the previous version of EnergyScope reported by Moret [7], the integer variables have been removed. In [7], they had the following use: (i) forcing the number of technologies to be an integer multiple of a reference size (e.g. one could only install 0.5, 1, 1.5, etc GW of CCGT if reference size is 0.5 GW); (ii) forcing that storage cannot charge and discharge at the same time; (iii) defining backup decentralised production technologies for thermal solar.

These variables were removed to reduce the computational time. As a consequence, (i) we accepted to have continuous size for installed capacities, such as 732 MW of CCGT; (ii) we systematically verify during the post treatment that a storage technology is not charging and discharging at the same time, which removes the need of using a binary variables. This change was also required to implement V2G, which can both charge and discharge. Complementarily, Eq. 19 verifies that the power charging and discharging are not higher than the maximum capacity. For example, assuming a case with 100 electric cars with a battery of 10kWh each, with an energy to power ratio of 10 (charging) and 5 (discharging) and with 20% of the cars are available to drive or charge. In this case, the charge and discharge powers are limited to a maximum of 20 or 40 kW, respectively, or a mix of the two. Finally, (iii) as illustrated in

[11]The calculation is based on the annual capacity factor, the conversion efficiency and the average yearly irradiation. As an example, for PV, the efficiency in 2035 is estimated at 23% [18] with an average daily irradiation - similar to historical values - of 2820 Wh/m^2 in Belgium [21]. The capacity factor of solar is around 11.4%, hence specific area for 1 kW is $2820/24 \cdot 0.23/0.114 \approx 236.7$[MW/km^2=0.2367 [GW/km^2].

Section 1.3, the thermal solar implementation has been improved; the new formulation is more realistic and does not require the use of binary/integer variables.

2 Belgian energy system data

This appendix reports the input data for the application of the LP modeling framework to the case study of Belgium in the years 2035 and 2015, the latter used for model verification. The resources and technologies in Figure 2 of the paper are characterized in terms of energy and mass balances, cost (operating and investment), and environmental impact (global warming potential (GWP)).

For GHG emissions, LCA data are taken from the Ecoinvent database v3.2[12] [8] using the "allocation at the point of substitution" method. GWP is assessed with the "GWP100a - IPCC2013" indicator. For technologies, the GWP impact accounts for the technology construction; for resources, it accounts for extraction, transportation and combustion. In addition, data for fuel combustion are taken from Quaschning [9].

For the cost, the reported data are the nominal values for Belgium in the year 2035 All costs are expressed in *real*[13] Euros for the year 2015 (€$_{2015}$). All cost data used in the model originally expressed in other currencies or referring to another year are converted to €$_{2015}$ to offer a coherent comparison. Most of the data come from a previous work [7, 10], and were expressed in CHF_{2015} (Based on the average annual exchange rate value from European Central Bank (ECB) `https://www.ecb.europa.eu`, the annual rate was 1€$_{2015}$ = 1.0679CHF_{2015}). The method used for the conversion is illustrated by Eq. 40.

$$c_{inv}[€_{2015}] = c_{inv}[C_y] \cdot \frac{\text{USD}_y}{C_y} \cdot \frac{\text{CEPCI}_{2015}\ [\text{USD}_{2015}]}{\text{CEPCI}_y\ [\text{USD}_y]} \cdot \frac{€_{2015}}{\text{USD}_{2015}} \tag{40}$$

Where C and y are the currency and the year in which the original cost data are expressed, respectively, USD is the symbol of American Dollars and the Chemical Engineering's Plant Cost Index (CEPCI) [11] is an index taking into account the evolution of the equipment cost (values reported in Table 5). As an example, if the cost data are originally in EUR_{2010}, they are first converted to USD_{2010}, then brought to USD_{2015} taking into account the evolution of the equipment cost (by using the CEPCI), and finally converted to €2015. The intermediate conversion to USD is motivated by the fact that the CEPCI is expressed in *nominal* USD. Although this conversion method is originally defined for technology-related costs, in this paper as a simplification it used also for the cost of resources.

2.1 Energy demand

The end-use demand (EUD) for heating, electricity and mobility in 2035 is calculated from the forecast done by the European Union Commission in 2035 for Belgium (see Appendix 2 in [4]). However, in [4], the final energy consumption (FEC) is given for heating and electricity. The difference between FEC and EUD is given in Section 1.1 and can be summarised as follow: the FEC is the amount of input energy needed to satisfy the EUD in energy services. Except for HP, the FEC is greater than EUD. We applied a conservative approach by assuming that the EUD equal to the FEC for electricity and heating demand.

[12] The database is consulted online: `http://www.ecoinvent.org`

[13] *Real* values are expressed at the net of inflation. They differ from *nominal* values, which are the actual prices in a given year, accounting for inflation.

Table 5: CEPCI values [11]

Year	CEPCI
1982	285.8
1990	357.6
1991	362.3
1992	367.0
1993	371.7
1994	376.4
1995	381.1
1996	381.7
1997	386.5
1998	389.5
1999	390.6
2000	394.1
2001	394.3
2002	395.6
2003	402.0
2004	444.2
2005	468.2
2006	499.6
2007	525.4
2008	575.4
2009	521.9
2010	550.8
2011	585.7
2012	584.6
2013	567.3
2014	576.1
2015	556.3

2.1.1 Electricity

The values in table 6 list the electricity demand that is not related to heating for the three sectors in 2035. The overall electricity EUD is given in [4]. However, only the final energy consumption (FEC) is given by sectors. In order to compute the share of electricity by sector, we assume that the electricity to heat ratio for the residential and services remain constant between 2015 and 2035. This ratio can be calculated from European Commission - Eurostat. [12], these ratio of electricity consumed are 24.9% and 58.2% for residential and services, respectively. As a consequence, the industrial electricity demand is equal to the difference between the overall electricity demand and the two other sectors.

A part of the electricity is assumed to be a fixed demand, such as fridges in households and services, or industrial processes. The other part is varying, such as the lighting demand. The ratio between varying electricity and fixed demand are the one of Switzerland, presented in [7, 10] which are based on [13]. The varying demand of electricity is shared over the year according to $\%_{elec}$, which is represented in Figure 7. We use the real 2015 Belgian electricity demand (data provided by ENTSO-E `https://www.entsoe.eu/`). $\%_{elec}$ time series is the normalised value of the difference between the real time series and its minimum value.

Table 6: Yearly electricity demand not related to heating by sector.

	Varying [TWh]	**Constant** [TWh]
Households	1.03	26.37
Industry	7.97	31.47
Services	2.70	22.34

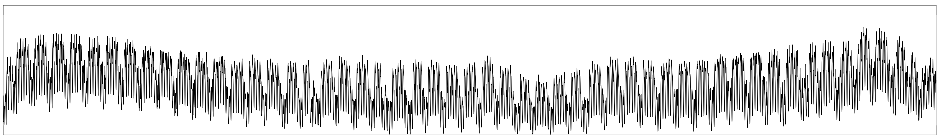


Figure 7: Normalised electricity time series over the year.

2.1.2 Heating

We applied the same methodology as in previous paragraph to compute the residential, service heat yearly demand. The industrial heat processes demand is assumed to be the overall industrial energy demand where electricity and non energy use have been removed. Yearly EUD per sector is reported in table 7.

A part of the heat is assumed to be a fixed demand, such as hot water in households and services, or industrial processes. The other part represents the space heating demand and is varying. Similarly to the electricity, the ratio between varying electricity and fixed demand are the one of Switzerland, presented in [7, 10] which are based on [13]. The varying demand of heat is shared over the year according to $\%_{sh}$, which is represented in Figure 9. This time series is based on our own calculation. The methodology is the following: based on the temperature time series of Uccle 2015 (data from Institut Royal Météorologique (IRM) [14]); the heat degree hour (HDH) are calculated; and then the time series. The HDH is a similar approach than the more commonly used heat degree day (HDD). According to Wikipedia, HDD is defined as follow : "*HDD is a measurement designed to quantify the demand for energy needed to heat a building. HDD is derived from measurements of outside air temperature. The heating requirements for a given building at a specific location are considered to be directly proportional to the number of HDD at that location. [...] Heating degree days are defined relative to a base temperature*". According to the European Environment Agency[14], the base temperature is 15.5^{o}C, we took 16^{o}C. HDH are computed as the difference between ambient temperature and the reference temperature at each hour of the year. If the ambient temperature is above the reference temperature, no heating is needed. Figure 8 compares the result of our methodology with real value collected by Eurostat[15]. The annual HDD was 2633, where we find 2507.

By normalising the HDH, we find $\%_{sh}$, which is represented in Figure 9.

2.1.3 Mobility

The annual passenger transport demand in Belgium for 2035 is expected to be 194e09 passenger-kilometers (pkms) [4]. Passenger transport demand is divided between public and private

[14]From `https://www.eea.europa.eu/data-and-maps/indicators/heating-degree-days-2`

[15]Source: `https://ec.europa.eu/eurostat`, consulted the 06/12/2019.

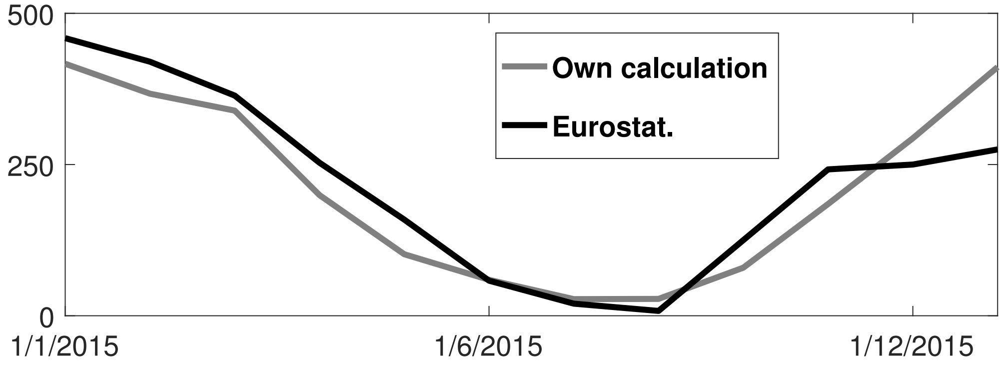


Figure 8: Comparison of heat degree day between Eurostat and our own calculation.

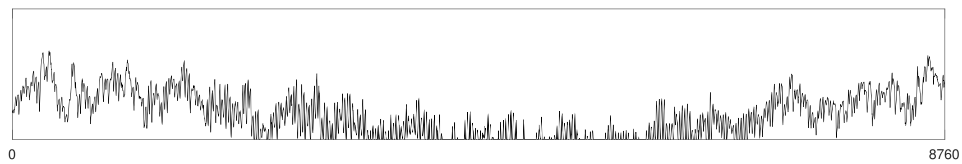


Figure 9: Normalised space heating time series over the year.

Table 7: Yearly heat end use demand per sector.

	Space heating [TWh]	**Hot water** [TWh]	**Process heat**[a] [TWh]
Households	65.9	16.8	0
Industry	17.0	5.2	65.3
Services	23.1	4.4	0

[a]We define process heat as the high temperature heat required in the industrial processes. This heat cannot be supplied by technologies such as heat pumps or thermal solar.

transport. The lower ($\%_{public,min}$) and upper bounds ($\%_{public,max}$) for the use of public transport are 19.9%[16] and 50% of the annual passenger transport demand, respectively. The passenger mobility demand is shared over the day according to $\%_{pass}$. We assume a constant passenger mobility demand for every day of the year. This latter is represented in Figure 10 (data from Figure 12 of [17]).
The annual freight transport demand in Belgium for 2035 is expected to be 98e09 tons-kilometers ton-kilometers (tkms) [4]. The freight can be supplied by trucks, trains or boats. The lower ($\%_{fr,rail,min}$) and upper bounds ($\%_{fr,rail,max}$) for the use of freight trains are 10.9%[16] and 25% of the annual freight transport demand, respectively. The lower ($\%_{fr,boat,min}$) and upper bounds ($\%_{fr,boat,max}$) for the use of freight inland boats are 15.6%[16] and 30% of the annual freight transport demand, respectively.
The lower ($\%_{fr,trucks,min}$) and upper bounds ($\%_{fr,trucks,max}$) for the use of freight trucks are 0% and 100% of the annual freight transport demand, respectively.
The bounds and technologies information are latter summarised in Table 14.

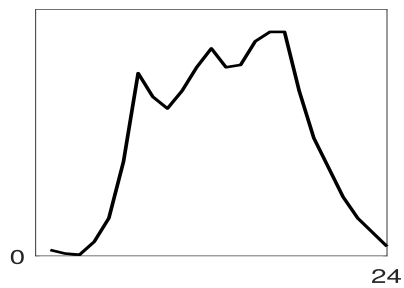


Figure 10: Normalised passenger mobility time series over a day. We assume a similar passenger mobility demand over the days of the year.

[16] it corresponds to the share of 2015 (From Tables 2.2.3 and 2.3.3 of [15]), in line with data from the service public fédéral (SPF) [16].

2.2 Electricity production

2.2.1 Renewables

Table 8: Renewable electricity production technologies. Abbreviations: onshore (on.), offshore (off.).

	c_{inv} [€$_{2015}$/kW$_e$]	c_{maint} [€$_{2015}$/kW$_e$/y]	gwp_{constr} [kgCO$_2$-eq./kW$_e$]	**Lifetime** [y]	c_p [%]	f_{min} [GW]	f_{max} [GW]
Solar PV	870[a]	18.8[a]	2081 [8]	25[a] [19]	11.9[b]	0	59.2[d]
On. Wind Turbine	1040[e]	2.9[e]	622.9 [8]	30[e] [22]	24.3[b]	0	10[f]
Off. Wind Turbine	1930[e]	9.8[e]	622.9 [8]	30[e] [22]	41.2[b]	0	3.5[f]
Hydro River	5045 [24]	50.44 [24]	1263 [8]	40 [24]	48.4	0.38 [25]	0.38 [25]
Geothermal[g]	7488[g]	142[g]	24.9 [8]	30	86 [27]	0	0[h]

[a] Investment cost based on [18]. operation and maintenance (O&M) cost scaled proportionally based on IEA data.

[b] Based on the real data of 2015 (data provided by ELIA, the Belgian transmission system operator (TSO), which monitored 2952MW of PV, onshore and offshore in 2015[c]).

[d] Assuming that 250 km^2 of available roof well oriented exist today [20] and that the efficiency in 2035 will be 23% [18] with an average irradiation - similar to historical values - of 2820 Wh/m^2 in Belgium, [21]. The upper limit becomes 59.2 GW of installed capacity.

[e] Onshore and offshore wind turbines in 2030 [18].

[f] From previous study [23]

[g] Organic Rankine cycle (ORC) cycle at 6 km depth for electricity production. Based on Table 17 of [26]. We took the reference case in 2030.

[h] A prototype (Balmatt project) started in 2019 and produces 4-5 MW [28]. However, the potential is not accurately known.

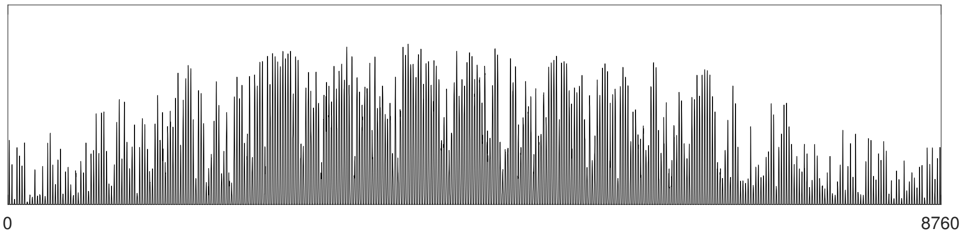
Data for the considered renewable electricity production technologies are listed in Table 8, including the yearly capacity factor (c_p). As described in the Section 1.3, for seasonal renewables the capacity factor $c_{p,t}$ is defined for each time period. These capacity factors are represented in Figure 11. For these technologies, c_p is the average of $c_{p,t}$. For all the other electricity supply technologies (renewable and non-renewable), $c_{p,t}$ is equal to the default value of 1. As the power delivered by the hydro river is almost neglectable, we take the time series of previous work for Switzerland [10].

2.2.2 Non-renewable electricity supply technologies

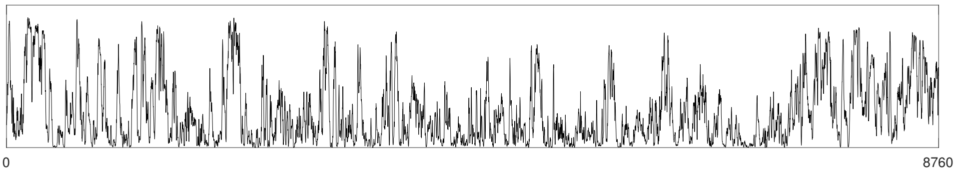
Data for the considered fossil electricity production technologies are listed in Table 9. The maximum installed capacity (f_{max}) is set to a value high enough (100 TW$_e$) for each technology to potentially cover the entire demand.

2.2.3 Electricity grid

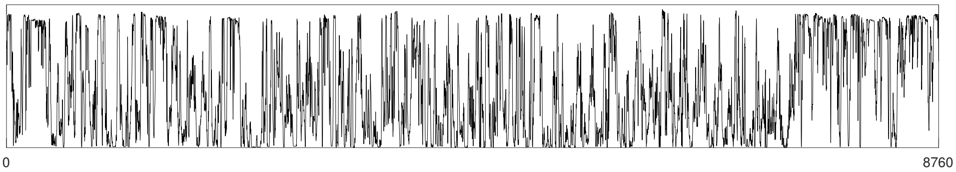
No data were found for the Belgian grid. Hence, by assuming that the grid cost is proportional to the population, the Belgian grid cost can be estimated based on the known Swiss grid cost. In 2015, the population of Belgium and Switzerland were 11.25 and 8.24 millions, respectively (Eurostat). The replacement cost of the Swiss electricity grid is 58.6 billions CHF$_{2015}$ [35] and its lifetime is 80 years [36]. The electricity grid will need additional investment depending on the penetration level of the decentralized and stochastic electricity production technologies. The needed investements are expected to be 2.5 billions CHF$_{2015}$ for the high voltage grid and 9.4



(a) Photovoltaic production



(b) Onshore Wind turbines production



(c) Offshore Wind turbines production

Figure 11: Capacity factor for the different renewable energy sources over the year.

Table 9: Non-renewable electricity supply technologies. Abbreviations: natural gas combined cycle (CCGT), ultra-supercritical (U-S), integrated gasification natural gas combined cycle (IGCC)

	$\boldsymbol{c_{inv}}$ [€$_{2015}$/kW$_e$]	$\boldsymbol{c_{maint}}$ [€$_{2015}$/kW$_e$/y]	$\boldsymbol{gwp_{constr}}$ [kgCO_2-eq./kW$_e$]	**Lifetime** [y]	$\boldsymbol{c_p}$ [%]	$\boldsymbol{\eta_e}$ [%]
Nuclear	4846[a]	103 [29]	707.9 [8]	60 [31]	84.9[b]	37
CCGT	772 [29]	20 [29]	183.8 [8]	25 [33]	85.0	63[c]
U-S Coal	2517[d]	30[d]	331.6[e] [8]	35 [33]	86.8 [33]	49[f]
IGCC	3246[g]	49[g]		35 [33]	85.6 [33]	54[h]

[a] Investment cost: 3431 €$_{2015}$/kW$_e$ [29] + dismantling cost in Switzerland: 1415 €$_{2015}$/kW$_e$ [30].

[b] Data for the year 2012 [32]

[c] 0.4-0.5 GW$_e$ CCGT in 2035 (realistic optimistic scenario) [33].

[d] 1.3 GW$_e$ advanced pulverized coal power plant [34]. c_{maint} is fixed cost (29.2 €$_{2015}$/kW$_e$/y) + variable cost (0.51 €$_{2015}$/kW$_e$/y assuming 7600 h/y).

[e] In the lack of specific data, assuming same impact for coal power plants.

[f] Pulverized coal in 2025 (realistic optimistic scenario) [33].

[g] 1.2 GW$_e$ IGCC power plant [34]. c_{maint} is fixed cost (48.1 €$_{2015}$/kW$_e$/y) + variable cost (0.82 €$_{2015}$/kW$_e$/y assuming 7500 h/y).

[h] integrated gasification natural gas combined cycle (IGCC) in 2025 (realistic optimistic scenario) [33].

billions CHF_{2015} for the medium and low voltage grid. These values correspond to the scenario 3 in [35]. The lifetime of these additional investments is also assumed to be 80 years.

As a consequence, the estimated cost of the Belgian grid is $58.6/1.0679 \cdot 11.25/8.24 = 74.9$ b€$_{2015}$. And the extra cost is $(9.4 + 2.5)/1.0679 \cdot 11.25/8.24 = 15.21$ b€$_{2015}$.

2.3 Heating and cogeneration technologies

Table 10, Table 11 and Table 12 detail the data for the considered industrial, centralized and decentralized CHP technologies, respectively. In some cases, it is assumed that industrial (Table 10) and centralized (Table 11) technologies are the same.
f_{min} and f_{max} for heating and CHP technologies are 0 and 100 TW_{th}, respectively. The latter value is high enough for each technology to supply the entire heat demand in its layer. Thus, for heating and cogeneration technologies the maximum and minimum shares are controlled in the model by $f_{min,\%}$ and $f_{max,\%}$, respectively.

Table 10: Industrial heating and cogeneration technologies.

	c_{inv} [€$_{2015}$/kW$_{th}$]	c_{maint} [€$_{2015}$/kW$_{th}$/y]	gwp_{constr} [kgCO$_2$-eq./kW$_{th}$]	Lifetime [y]	c_p [%]	η_e [%]	η_{th} [%]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
CHP NG	1408[a]	92.6[b]	1024 [8]	20 [33]	85	44[c]	46[c]	0	100
CHP Wood[d]	1080 [29]	40.5 [29]	165.3 [8]	25 [38]	85	18 [29]	53 [29]	0	100
CHP Waste	2928[e]	111.3[e]	647.8[f]	25 [38]	85	20 [38]	45 [38]	0	100
Boiler NG	58.9[g]	1.2[g]	12.3[h]	17 [39]	95	0	92.7[g]	0	100
Boiler Wood	115[g]	2.3[g]	28.9 [8]	17 [39]	90	0	86.4[g]	0	100
Boiler Oil	54.9[i]	1.2[j]	12.3 [8]	17 [39]	95	0	87.3[g]	0	100
Boiler Coal	115[k]	2.3[k]	48.2 [8]	17 [39]	90	0	82	0	100
Boiler Waste	115[k]	2.3[k]	28.9[l]	17 [39]	90	0	82	0	100
Direct Elec.	332[m]	1.5[m]	1.47 [8]	15	95	0	100	0	100

[a] Calculated as the average of investment costs for 50 kW_e and 100 kW_e internal combustion engine cogeneration systems [13].
[b] Calculated as the average of investment costs for 50 kW_e and 100 kW_e internal combustion engine cogeneration systems [37].
[c] 200 kW_e internal combustion engine cogeneration NG system, very optimistic scenario in 2035 [33].
[d] Biomass cogeneration plant (medium size) in 2030-2035.
[e] Biomass-waste-incineration CHP, 450 scenario in 2035 [29].
[f] Impact of municipal solid waste (MSW) incinerator in [7], using efficiencies reported in the table.
[g] from [7]
[h] Assuming same impact as industrial oil boiler.
[i] 925 kW_{th} oil boiler (GTU 530) [40]
[j] Assumed to be equivalent to a NG boiler.
[k] Assumed to be equivalent to a wood boiler.
[l] Assuming same impact as industrial wood boiler.
[m] Commercial/public small direct electric heating [41].

For the DHN, the investment for the network is also accounted for. The specific investment (c_{inv}) is 882 CHF_{2015}/kW_{th} in Switzerland. This value is based on the mean value of all points in [45] (Figure 3.19), assuming a full load hours of 1535 per year (see table 4.25 in [45]). The lifetime of the DHN is expected to be 60 years.

As no relevant data where found for Belgium, the DHN infrastructure cost of Switzerland was used for Belgium. As a consequence, the investment cost (c_{inv}) is 825 €$_{2015}$/kW$_{th}$. Based on the heat roadmap study [46], heat provided by DHN is "*around 2% of the heating for the built environment (excluding for industry) today to at least 37% of the heating market in 2050*". Hence, the lower ($\%_{dhn,min}$) and upper bounds ($\%_{dhn,max}$) for the use of DHN are 2% and 37% of the annual low temperature heat demand, respectively.

Table 11: District heating technologies.

	c_{inv} [€$_{2015}$/kW$_{th}$]	c_{maint} [€$_{2015}$/kW$_{th}$/y]	gwp_{constr} [kgCO$_2$-eq./kW$_{th}$]	**Lifetime** [y]	c_p [%]	η_e [%]	η_{th} [%]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
HP	345[a]	12.0[b]	174.8 [8]	25	95	0	400	0	100
CHP NG	1254[c]	37.5[c]	490.9[d]	25 [33]	85	50[e]	40[e]	0	100
CHP Wood[f]	1081 [29]	40.5	165.3	25 [38]	85	18 [29]	53 [29]	0	100
CHP Waste[f]	2928	111	647.8	25 [38]	85	20 [38]	45 [38]	0	100
CHP Wet biomass	2287[g]	228.7[g]	1024	25[g]	75[g]	35 [g]	40 [g]	0	100
Boiler NG[f]	58.9[h]	1.2[h]	12.3	17 [39]	95	0	92.7[h]	0	100
Boiler Wood[f]	115[h]	2.3[h]	28.9	17 [39]	90	0	86.4[h]	0	100
Boiler Oil[f]	54.9	1.2	12.3	17 [39]	95	0	87.3[h]	0	100
Geothermal[i]	1500[i]	57.0[i]	221.8 [8]	30[i]	85	0	100	0	100
Solar thermal[j]	362[j]	0.43[j]	808.8 [8]	30[j]	10	0	100	0	100

[a] Calculated with the equation: c_{inv} [EUR$_{2011}$] $= 3737.6 * E^{0.9}$, where E is the electric power (kW$_e$) of the compressor, assumed to be 2150 kW$_e$. Equation from [42], taking only the cost of the technology (without installation factor).

[b] Ground-water heat pump with 25 years lifetime [43].

[c] CCGT with cogeneration [29].

[d] Impact of NG CHP in from [7], using efficiencies reported in the table.

[e] η_e and η_{th} at thermal peak load of a 200-250 MW$_e$ CCGT plant, realistic optimistic scenario in 2035 [33].

[f] Assumed same technology as for industrial heat and CHP (Table 10)

[g] Assumed same technology as *anaerobic digestion with gas engine-based CHP* plant with invesment cost of 3000USD$_{2008}$/kWe and operating and mainteannce cost of 300USD$_{2008}$/kWe/y (based on learning curve fig. 12). Data from IEA: [44]

[h] from [7]

[i] Geothermal haet-only plant with steam driven absorption heat pump 70/17^{o}C at 2.3 km depth (from [18]).

[j] Total system excluding thermal storage (from [18]).

Figure 12 represents the capacity factor ($c_{p,t}$) of solar thermal panels. The time series is the direct irradiation in Uccles in 2015, based on measurements of IRM. For all the other heat supply technologies (renewable and non-renewable) $c_{p,t}$ is equal to the default value of 1.

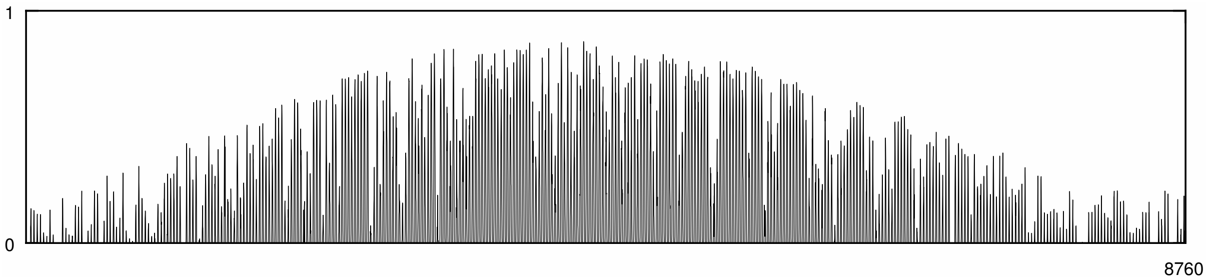


Figure 12: Capacity factor of thermal solar panels over the year.

2.4 Transport

In the model, for transport technologies only the operating cost (fuel consumption) is considered. Investment, O&M costs and emissions associated to the construction are not accounted for. The efficiencies for the passenger vehicles in 2035 (Table 13) are calculated with a linear interpolation between the 2010 and 2050 values presented in Table 6 in Codina Gironès et al [52]. For private mobility, the average occupancy assumed in [52] is 1.6 passenger/vehicle (data for the year 2010 in Switzerland, from [53], in reality in Belgium in 2030, the Federal Planning Bureau (FPB)

Table 12: Decentralized heating and cogeneration technologies.

	c_{inv} [€$_{2015}$/kW$_{\text{th}}$]	c_{maint} [€$_{2015}$/kW$_{\text{th}}$/y]	gwp_{constr} [kgCO$_2$-eq./kW$_{\text{th}}$]	**Lifetime** [y]	c_p [%]	η_e [%]	η_{th} [%]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
HP	492^{ab}	21^{c}	164.9 [8]	18^{c}	100	0	300	0	100
Thermal HP	316^{db}	9.5^{e}	381.9 [8]	20	100	0	150	0	100
CHP NG^{f}	1408	92.6	1024	20 [33]	100	44	46	0	100
CHP Oil	1306^{g}	82.0^{g}	1024^{h}	20	100	39^{i}	43^{i}	0	100
fuel cell (FC) NG	7242^{j}	144.8^{k}	2193 [8]	20 [50]	100	58^{l}	22^{l}	0	100
FC H$_2$^{m}	7242	144.8	2193	20 [50]	100	58	22	0	100
Boiler NG	159^{n}	5.08^{n}	4.8^{n}	17 [39]	100	0	90^{n}	0	100
Boiler Wood	462 [51]	16 [51]	21.1^{o}	17 [39]	100	0	85 [51]	0	100
Boiler Oil	142 [40]	8.5^{p}	21.1^{n}	17 [39]	100	0	85^{n}	0	100
Solar Th.	719^{q}	8.1^{r}	221.2 [8]	20 [41]	11.3^{s}	0	-	0	100
Direct Elec.	40^{t}	0.18^{u}	1.47 [8]	15 [41]	100	0	100	0	100

[a] 10.9 kW$_{\text{th}}$ Belaria compact IR heat pump [47].

[b] Catalog data divided by 2.89. 2.89 is the ratio between Swiss catalog prices and prices found in the literature. Calculated by dividing the average price of a decentralized NG boiler (489 CHF$_{2015}$/kW$_{\text{th}}$) in Swiss catalogs [48] by the price for the equivalent technology found in literature (169 CHF$_{2015}$/kW$_{\text{th}}$, from [7]).

[c] 6 kW$_{\text{th}}$ air-water heat pump [41].

[d] Specific investment cost for a 15.1 kW$_{\text{th}}$ absorption heat pump (Vitosorp 200-F) [48]

[e] 3% of c_{inv} (assumption).

[f] Assumed same technology as for industrial CHP NG (Table 10)

[g] Assumed to be equivalent to a 100 kW$_{\text{e}}$ internal combustion engine cogeneration NG system [13, 37].

[h] Assuming same impact as decentralized NG CHP.

[i] Efficiency data for a 200 kW$_{\text{e}}$ diesel engine [8]

[j] System cost (including markup) for a 5 kW$_{\text{e}}$ solid-oxide FC system, assuming an annual production of 50000 units [49].

[k] 2% of the investment cost [29].

[l] Solid-oxide FC coupled with a NG turbine, values for very optimistic scenario in 2025 [50].

[m] Assumed to be equivalent to FC NG.

[n] from [7]

[o] Assuming same impact as NG and oil decentralized boilers.

[p] 6% of c_{inv}, based on ratio between investment and O&M cost of boiler of similar size in [39].

[q] 504 CHF$_{2015}$/m^2 for the UltraSol Vertical 1V Hoval system [47]. For conversion from CHF$_{2015}$/m^2 to CHF$_{2015}$/kW$_{\text{th}}$, it is assumed an annual heat capacity factor of 6.5% based on Uccles data.

[r] 1.1% of the investment cost, based on ratio investment-to-O&M cost in [41].

[s] The calculation of the capacity factor for solar thermal is based on the IRM model [21] with radiation data from the village of Uccles, Belgium.

[t] Resistance heaters with fan assisted air circulation in [39].

[u] In the lack of specific data, same investment-to-O&M ratio as for direct electric heating in the industry sector (Table 10).

estimates the average occupancy around 1.26 passenger/vehicle [54]).

Table 13: Fuel and electricity consumption for passenger mobility technologies in 2035 [52], and minimum/maximum shares allowed in the model.

Vehicle type	**Fuel** [kWh/pkm]	**Electricity** [kWh/pkm]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
Gasoline car	0.430		0	100
Diesel car	0.387		0	100
NG car	0.483		0	100
Hybrid electric vehicle (HEV)[a]	0.247		0	100
Plug-in hybrid electric vehicle (PHEV)[b]	0.176	0.037	0	100
BEV		0.107	0	100
FC car	0.179		0	100
Tram and Trolley Bus		0.165	0	30
Diesel Bus and Coach	0.266		0	30
Diesel HEV Bus and Coach	0.183		0	30
NG Bus and Coach	0.306		0	30
FC Bus and Coach	0.226		0	20
Train		0.092	0	80

[a] Using gasoline as only fuel.
[b] It is assumed that electricity is used to cover 40% of the total distance and petrol to cover the remaining 60%.

Table 14: Fuel and electricity consumption for freight mobility technologies in 2035 [52], and minimum/maximum shares allowed in the model [15].

Vehicle type	**Fuel** [kWh/tkm]	**Electricity** [kWh/tkm]	$f_{min,\%}$ [%]	$f_{max,\%}$ [%]
Train	0	0.068	10.9	25
Diesel boat	0.107		15.6	30
NG boat	0.123		15.6	30
Diesel truck	0.51		0	100
NG truck	0.59		0	100
FC truck	0.44		0	100
Train		0.092	0	80

The technologies available for freight transport are trains, trucks and boats (see Table 14). Based on [4], in 2015, the efficiency of "*Heavy goods and light commercial vehicles*", inland navigation and trains[17] were 0.838, 0.158 and 0.144 kWh/tkm, respectively.

Trains are considered to be only electric. Their efficiency in 2035 is 0.068 kWh/tkm [52]. The efficiency for freight transport by diesel truck is 0.51 kWh/tkm based on the weighted average of the efficiencies for the vehicle mix in [52]. For NG and di-hydrogen (H2) trucks, no exact data were found. Hence, we assume that the efficiency ratio between NG coaches and diesel coaches can be used for freight (same for H2 trucks). As a consequence, the efficiency of NG

[17] To calculate the energy consumption of freight trains, we removed the energy consumed of passenger trains and found 99 ktoe.

and H2 trucks are 0.59 and 0.44 kWh/tkm. Boats are considered to be diesel or gas powered. In 2015, the energy intensity ratio between diesel boats and diesel trucks were ≈20%[18]. By assuming a similar ratio in 2035, we find an efficiency of 0.107 kWh/tkm and 0.123 kWh/tkm for diesel and gas boats, respectively.

The maximum number of cars is assumed to be equivalent to have all the drivers owning a car (6.55 millions person in Belgium). The size of the BEV batteries is assumed to be the one from a Nissan Leaf (ZE0) (24 kWh[19]). The size of the PHEV batteries is assumed to be the one from Prius III Plug-in Hybrid (4.4 kWh[20]). The performances of BEV and PHEV batteries are assimilated to a Li-ion battery as presented in Table 17.

2.5 Resources

The availability of all resources, except for biomass, and non-RE waste, is set to a value high enough to allow unlimited use in the model. No import of synthetics or biofuels is accounted for in the implementation. Based on European Union Commission (EUC) work [4], the amount of waste and biomass used in 2035 is 39.53 TWh. In 2015, this ressources was shared in woody biomass (41.7%), wet biomass (34.7%) and non-RE waste (23.6%) [55]. These shares are assumed identical in 2035. Table 15 details the prices of resources (c_{op}), the GHG emissions (gwp_{op}) associated to their production, transportation and combustion; and endogenous availability of resources. c_{op} for imported synthetic or biofuels is assumed to be equal to the price of the respective fossil equivalent. No cost is associated to the non-RE waste, as it is assumed that it should be collected anyway. Export of electricity are possible, but they are associated to a zero selling price. Two kinds of emissions are proposed: one accounting for the impact associated to production, transport and combustion (based on GWP100a - IPCC2013 [7]); the other accounting only for combustion (based on Quaschning [9]). Total emissions are used to assess energy system emissions. Combustion only is used to calculate the direct carbon dioxide (CO_2) emissions that can be captured and used through a carbon capture technology (latter presented).

2.6 Storage

Table 16 and 17 detail the data for the storage technologies. Table 16 summarises the investment cost, GWP, lifetime and potential integration of the different technologies. Table 17 summarises the technical performances of each technology.

The PHS in Belgium can be resumed to the Coo-Trois-Ponts hydroelectric power station. The characteristics of the station in 2015 are the following: installed capacity turbine (1164MW), pumping (1035MW), overall efficiency of 75%, all reservoirs capacity (5000 MWh). We assume that the energy losses is shared equally between the pumping and turbining, resulting by an charge/discharge efficiencies of 86.6%. The energy to power ratio are 4h50 and 4h18 for charge and discharge, respectively [67]. A project started to increase the height of the reservoirs and thus increase the capacity by 425 MWh. In addition, the power capacity will be increase by 80MW. The overall project cost is estimated to 50M€ and includes also renovation of other parts[21]. We arbitrary assume that 50% is dedicated for the height increase. It results in an

[18] Value calculated based on the ratio between the transported tons and the consumed energy per technologies in 2015. Data from [4]

[19] from `https://en.wikipedia.org/wiki/Nissan_Leaf`, consulted on 29-01-2019

[20] from `https://fr.wikipedia.org/wiki/Toyota_Prius`, consulted on 29-01-2019

[21] This information was shared by Engie, the facility manager `https://corporate.engie-electrabel.be/projet-extension-centrale-coo/` and also publicised by newspapers: `https://www.renouvelle.be/fr/actualite-belgique/la-centrale-de-coo-augmente-sa-capacite-de-stockage`, `https://www.lameuse.be/403176/article/2019-06-20/va-agrandir-les-lacs-de-la-centrale-coo`.

Table 15: Price, GHG emissions and availability of resources.

Resources	$\boldsymbol{c_{op}}$ [€$_{2015}$/MWh$_{\text{fuel}}$]	$\boldsymbol{gwp_{op}}$ [kgCO$_2$-eq./MWh$_{\text{fuel}}$]	$\boldsymbol{CO_{2direct}}^a$ [kgCO$_2$/MWh$_{\text{fuel}}$]	*avail* [TWh]
Electricity Import	84.3^b	482^c	0	∞
Gasoline	82.4^d	345^c	250	∞
Diesel	79.7^e	315^c	270	∞
Light fuel oil (LFO)	56.7^f	311.5^c	260	∞
NG	41.5^g	267^c	200	∞
Biomass	26.2^g	11.8^c	390	30.2^h
non-RE waste	0	150^c	260^i	9.3
Coal	17.6^g	401 [8]	360	∞
Uranium	3.9^j	3.9 [8]	0	∞

[a] Direct emissions related to combustion[9].

[b] Based on average market price in the year 2010 (50 EUR$_{2010}$/MWh, from [56]). Projected from 2010 to 2035 using a multiplication factor of 1.36 [13].

[c] GWP100a-IPCC2013 metric: impact associated to production, transport and combustion, see [7]

[d] Based on 1.49 CHF$_{2015}$/L (average price in 2015 for gasoline 95 in Switzerland) [57]. Taxes (0.86 CHF$_{2015}$/L, [58]) are removed and the difference is projected from 2015 to 2035 using a multiplication factor of 1.24 [59]. In line with [60].

[e] Based on 1.55 CHF$_{2015}$/L (average price in 2015) [57]. Taxes (0.87 CHF$_{2015}$/L, [58]) are removed and the difference is projected from 2015 to 2035 using a multiplication factor of 1.24 [59]. In line with [60].

[f] Based on 0.705 CHF$_{2015}$/L (average price in 2015 for consumptions above 20000 L/y) [61]. Taxes (0.22 CHF$_{2015}$/L, [58]) are removed and the difference is projected from 2015 to 2035 using a multiplication factor of 1.24 [59]. In line with [60].

[g] Based on the EUC estimated cost of resources in 2030, see Table 5 from [60].

[h] From which, 16.5 are woody and 13.7 are digestible.

[i] Assuming that the energy content can be assimilated to plastics and extended to LFO.

[j] Average of the data points for 2035 in [62], accounting for the efficiency of nuclear power plants (Table 9).

Table 16: Storage technologies characteristics: cost, emissions, lifetime and potential.

	$\mathbf{c_{inv}}$ [€$_{2015}$/kWh]	$\mathbf{c_{maint}}$ [€$_{2015}$/kWh/y]	$\mathbf{gwp_{constr}}$ [kgCO$_2$-eq./kW$_{th}$]	**Lifetime** [y]
Li-on batt.	302^a	0.62^a	61.3^b	15^c
PHS	58.8	0^d	8.33^e	50^f
TS dec.	19.0^g	0.13^g	0^d	25^g
TS seas. cen.	0.54^h	0.003^h	0^d	25^h
TS daily cen.	3^h	0.0086^d	0^d	40^g
NG	0.051^i	1.3e-3^i	0^d	30^i
H2	6.19^j	3.0e-2^j	0^d	20^j
SLF	6.35e-3^k	3.97e-4^k	0^d	20^k
CO_2^{l}	49.5^m	0.495^{lm}	0^d	20^l

[a] We assume a Lithium-ion NMC battery at a utility-scale in 2030 [63] with average use of 100 cycles/year.

[b] Data from Table 4 of [23].

[c] Trade off between various sources: [63, 64]

[d] Neglected.

[e] Own calculation based on Hydro Dams emissions from previous work [7, 10].

[f] Data verified in Table B1 of [64].

[g] Adapted from Table 5.2 of [65].

[h] The technologies used are pit thermal energy storage technology and Large-scale hot water tanks for seasonal and daily DHN storage, respectively. Data was taken for year 2030 [63].

[i] Data from the Torup Lille project [63]. The lifetime is assumed similar to a cavern for hydrogen storage.

[j] Based on tank storage from the JRC project[60]. The cost is assumed as the average of 2020 and 2050 costs.

[k] In 2013, the IEA estimated the facility storage cost to be between 8 and 37 USD/barril [66]. Taking the cheapest option, the investment cost is 6.35€$_{2015}$/MWh. A similar methodology is applied to the operating and maintenance cost.

[l] Based on liquid CO_2 tank storage. Data from a datasheet of *Ever grow gas* company `https://www.evergrowgas.com/`. Lifetime and maintenance cost based on own calculation.

[m] Units: $\mathbf{c_{inv}}$ [€$_{2015}$/tCO_2], $\mathbf{c_{op}}$ [€$_{2015}$/tCO_2/y]

investment cost of 58.8€$_{2015}$ per kWh of new capacity. The overall potential of the PHS could be extended by a third reservoir with an extra capacity of around 1.2 GWh. Hence, we assume that the upper limit of PHS capacity is 6.5 GWh. No upper bound were constrained for other storage technologies.

Estimation for the gas storage is based on an existing facility using salt caverns as reservoirs: Lille Torup in Danemark [63]. The project cost is estimated to 254M€$_{2015}$ for an energy capacity of 4965 GWh. The yearly operating cost is estimated to 6.5 M€$_{2015}$. Part of it is for electricity and gas self consumption. We assume that the electricity is used for charging the system (compressing the gas) and the gas is used for heating up the gas during the discharge. These quantities slightly impact the charge and discharge efficiency of the system. The charge and discharge power are 2200 and 6600 respectively. As the technology is mature, we assume that the cost of the technology in 2035 will be similar to Lille Torup project.

Table 17: Storage technologies characteristics: efficiencies, energy to power ratios, losses and availabilities.

	$\eta_{sto,in}$ [-]	$\eta_{\mathbf{sto,out}}$ [-]	$\mathbf{t_{sto_{in}}}$ [h]	$\mathbf{t_{sto_{out}}}$ [h]	$\%_{sto_{loss}}$ [s^{-1}]	$\%_{sto_{avail}}$ [-]
Li-on batt.	0.95[a]	0.95[a]	4[a]	4[a]	2e-4[b a]	1
BEV batt.	0.95[a]	0.95[a]	4[c]	10[c]	2e-4[b a]	0.2[c]
PHEV batt.	0.95[a]	0.95[a]	4[c]	10[c]	2e-4[b a]	0.2[c]
PHS	0.866	0.866	4.30	4.83	0[d]	1
TS dec.	1[d]	1[d]	4[c]	4[c]	82e-4[e]	1
TS seas. cen.	1[f]	1[f]	150[f]	150[f]	6.06e-5[f]	1
TS daily cen.	1[f]	1[f]	60.3[f]	60.3[f]	8.33e-3[f]	1
NG	0.99[g]	0.995[g]	2256[g]	752[g]	0	1
H2	0.90[h]	0.98[i]	4[i]	4[i]	0	1
Synthetic liquid fuel (SLF)[i]	1	1	1	1	0	1
CO_2[i]	1	1	1	1	0	1

[a] Data verified in Table B1 of [64].
[b] Data from Table 4 of [23].
[c] Own calculation.
[d] Neglected.
[e] Adapted from Table 5.2 of [65]
[f] Based on the Pit thermal energy storage technology in 2030 for seasonal and Large-scale hot water tanks for DHN daily storage. Data from [63].
[g] Data from the Torup Lille project[63]. Efficiencies are based on our own calculation based on electricity and gas consumed by the installation over a year.
[h] Sadaghiani and Mehrpooya [68] an efficiency of 88.6% in an ideal configuration for liquid hydrogen liquefaction. This high efficiency is used and we arbitrary impose that the charge efficiency is 90% and the discharge 98%. The tank design by JRC [60] has a charge/discharge energy to power ratio of 4 hours.
[i] We assume a perfect storage.

2.7 Synthetic fuels

Synthetic fuels are expected to play a key role to phase out fossil fuels [69]. Figure 13 represents the technology related to synthetic fuels, including the carbon dioxide layers. Synthetic fuels can be imported (Bio-ethanol, Bio-Diesel, H2 or synthetic natural gas (SNG)) or produced by converting biomass and/or electricity. The wet biomass - usually organic waste - can

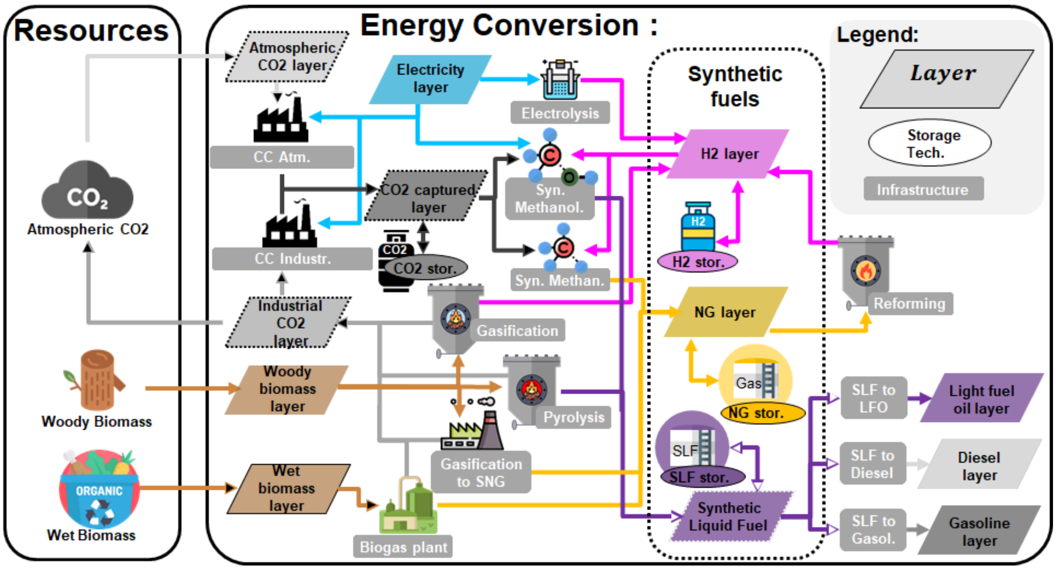


Figure 13: Illustration of the technologies and processes to produce synthetic fuels. For clarity, only the most relevant flows are drawn (Figure 2 of the main manuscript includes all the flows).

be converted through the *biogas plant* technology to SNG. This technology combines anaerobic digestion and cleaning processes (see Supplementary Material for additional information). Woody biomass can be used to produce H2 through *gasification*, or SLF through *pyrolysis* or SNG through *gasification to SNG*. The synthetic liquid fuel can later be converted into LFO, Gasoline or Diesel. The other processes to produce synthetic fuels are based on the water electrolysis, where the *electrolysers* convert electricity to H2. Then, the H2 can be combined with CO_2 and upgraded to SNG through the *methanation* technology. In this latter, the process requires CO_2. It can either be captured from large scale emitters, such as the industries and centralised heat technologies; or directly captured from the air but at a higher energetic and financial cost.

2.7.1 Hydrogen production

Three technologies are considered for hydrogen production: electrolysis, NG reforming and biomass gasification. The last two options include carbon capture and storage (CCS) systems for limiting the CO_2 emissions. Table 18 contains the data for the hydrogen production technologies.

Table 18: Hydrogen production technologies.

	c_{inv} [€$_{2015}$/kW$_{H2}$]	c_{maint} [€$_{2015}$/kW$_{H2}$/y]	Lifetime [y]	c_p [%]	η_{H2} [%]
Electrolysis [70]	308	31[a]	15	90	85
CH_4 reforming [71]	681	64.4	25[b]	86	73
Biomass gasification [71]	2525	196	25[b]	86	43

[a] Assumed to be 10% of c_{inv}, for coherence with the data in [71].
[b] Assumption.

2.7.2 Hydrogen to other synthetic fuels

Two technologies can convert hydrogen to more advanced fuels and are summarised in Table 19. Synthetic methanisation (*syn. methanisation*) and synthetic methanolation (*syn. methanolation*), which produce SNG and methanol (assimilated to SLF), respectively. This last can be freely converted to gasoline, diesel or LFO. Due to the low maturity of these technologies, no exact data where found. For power to methanol, we tooke the Vulcanol project. It is a power plant produces around 4000 tons of methanol per year[22]. This prototype has been built in Iceland to convert electricity from the grid and carbon dioxide to methanol [72]. The implemented technology converts hydrogen, CO_2 and electricity into methanol. During the process, heat losses are recovered for DHN. The cogeneration efficiency is estimated to be 86%. To represent the financial cost and technical efficiencies of the implemented technology, we substracted the economical and energitical cost of an electrolyser to an all-in-one installation proposed in [72].

The level of maturity of synthetic methanisation is lower than the methanol process. Its economical data has been assimilated to an advanced methanation of biogas technology where hydrogen is injected to generate more SNG, data from [72]. These data are corrected by removing the direct biogas process cost.

2.7.3 Biomass to synthetic fuels

Three technology options are considered for the conversion of biomass to synthetic fuels: pyrolysis, gasification and biomethanation. The main product of the pyrolysis process is bio-oil, which is considered equivalent to synthetic liquid fuel (SLF). The main product of the gasification and biomethanation processes are SNG, which is considered equivalent to fossil NG. Data for the technologies are reported in Table 19 (from [7]). The biomethanation process is based on anaerobic digestion followed by a cleaning process in order to have gas that can be reinjected in the gas grid [72, 73]. In the table, efficiencies are calculated with respect to the wood in input (50% humidity, on a wet basis lower heating value (LHV)) and "*fuel*" stands for the main synthetic fuel in output.

Table 19: Synthetic fuels (except H2) conversion technologies (from [7, 72]).

	c_{inv} [€$_{2015}$/kW$_{\text{fuel}}$]	c_{maint} [€$_{2015}$/kW$_{\text{fuel}}$/y]	**Lifetime** [y]	c_p [%]	η_{fuel} [%]	η_{e} [%]	η_{th} [%]
Pyrolysis	1344	67.2	25	85	66.6	1.58	-
Gasification	2744	140	25	85	74	3.15	9.01
Biomethanation[a]	1661	14	20	85	93.4	0	0
Syn. methanation[b]	1888	74.6	40	100	78	0	0
Syn. methanolation[72]	2750	54.5	20	95	63.9	0	26.1

[a]This technology combines a anaerobic digestion reactor and a cleaning process. Data from [72].
[b]The level of maturity is low and we based the technology on an advanced biomethanation process (including H2 input) and own calculation [72].

[22]See official website: `https://www.carbonrecycling.is`.

2.8 Other parameters

2.8.1 Energy demand reduction cost

By replacing former device at the end user side, the end-use demand can be reduced. This is usually called "*energy efficiency*". As an example, by insulating a house, the space heating demand can be reduced. However, energy efficiency has a cost which represents the extra cost of buying an efficient technology compare to a cheaper one. As in the model the demand reduction is fixed, hence the energy efficiency cost is fixed. The American Council for an Energy-Efficient Economy summarises study about the levelised cost of energy savings [74]. They conclude that this cost is below 0.04 USD_{2014}/kWh saved and around 0.024 USD_{2014}/kWh, hence 0.018€$_{2015}$/kWh. In 2015, Belgium final energy consumption was 415 TWh [55] and the energy efficiency around 15% compare to 1990. The European target is around 35% in 2035, hence the energy efficiency cost for Belgium between 2015 and 2035 is 3.32b€$_{2015}$. This result is in line with another study for Switzerland where the energy efficiency cost is 1.8b€$_{2015}$ for the same period and similar objectives [75] (see [7] for more details about Switzerland).

2.8.2 Carbon capture and storage

As represented in Figure 13, two technologies are proposed to capture the CO_2, one from atmosphere (*CC Atmospheric*) and the other from exhaust gases of conversions processes (*CC industry*), such as after a coal power plant. Indeed, resources emit direct CO_2 from combustion and *CC industry* can concentrate CO_2 contained in the exhaust gas and inject it in CO_2 captured layer. The same process can be performed at a higher energetical cost with CO_2 grom the atmosphere. No restriction on the available limit of CO_2 from the atmosphere is considered. Data are summarised in Table 20.

We suppose that *CC industry* is equivalent to the sequestration unit on a coal power plant as proposed in [18]. Based on our own calculation, we evaluated the economical and technical data. We assumed that the energy drop of the power plant represents the amount of energy that the sequestration unit consumes. We assume that this energy must be supplied by electricity.

For *CC atmospheric*, Keith et al. [76] proposed an installation where 1 ton of CO_2 is captured from the atmosphere with 1.3 kWh of natural gas and electricity. We assume that it can be done with 1.3 kWh of electricity. The thermodynamical limit is estimated to be around 0.2 kWh of energy to sequestrate this amount [77].

Table 20: carbon capture technologies. $\boldsymbol{E_e}$ represents the electricity required to capture sequestrate CO_2. $\boldsymbol{\eta_{CO_2}}$ represents the amount of CO_2 sequestrated from the CO_2 source. Abbreviations: industrial (ind.), atmospheric (atm.).

	$\boldsymbol{c_{inv}}$ [€$_{2015}$/tCO_2-h]	$\boldsymbol{c_{maint}}$ [€$_{2015}$/tCO_2-h/y]	**Lifetime** [y]	$\boldsymbol{E_e}$ [kWhe/tCO_2]	$\boldsymbol{\eta_{CO_2}}$ [%]	$\boldsymbol{f_{min,\%}}$ [%]	$\boldsymbol{f_{max,\%}}$ [%]
CC Ind.	2580	64.8	40	0.233	90[a]	0	100
CC Atm.	5160 [b]	129.6	40	1.3	100	0	100

[a]We consider that 10% of the CO_2 cannot be collected.

[b]Based on the economical data given in [76] and own calculation.

No relevant data were found for the load factor ($\boldsymbol{c_p}$) and the GWP associated to the unit construction.

2.8.3 Other

The real discount rate for the public investor i_{rate} is fixed to 1.5%.
Losses ($\%_{net_{loss}}$) in the electricity grid are fixed to 4.7%. This is the ratio between the losses in the grid and the total annual electricity production in Belgium in 2016 [15]. DHN losses are assumed to be 5%.

2.9 2015 data for model verification

This section details the data of the Belgian energy system in the year 2015 used to validate the LP model in the validation Section of the paper. The input data for the year 2015 used for the model validation are: *i*) the yearly EUD values in the different sectors ($endUses_{year}$); *ii*) the relative annual production shares of the different technologies for each type of EUD; *iii*) the share of public mobility ($\%_{\mathbf{Public}}$), of train and boat in freight ($\%_{\mathbf{Rail}}$, $\%_{\mathbf{Boat}}$) and of centralized heat production ($\%_{\mathbf{Dhn}}$); *iv*) the fuel efficiency of mobility technologies.

The FEC data for Belgium in the year 2015 are available in [4, 55]. The EUD is calculated based on the FEC using a similar procedure as the one described in Section 2.1.2. The obtained input data for model verification are reported in Table 21. $\%_{\mathbf{Public}}$, $\%_{\mathbf{Rail}}$, $\%_{\mathbf{Boat}}$ and $\%_{\mathbf{Dhn}}$ are reported in Table 22 with the corresponding sources.

Table 21: End-uses demand in Belgium ($endUses_{year}$) in 2015, calculated from [4, 55].

	Units	**Households**	**Services**	**Industry**	**Transportation**
Electricity (other)	[GWh]	25705.8	30900	14402	0.0
Lighting	[GWh]	1007	7825	1743	0.0
Heat high T	[GWh]	0	0	93620	0.0
Heat low T (SH)	[GWh]	64217	22728	24350	0.0
Heat low T (HW)	[GWh]	16414	5094	6309	0.0
Passenger mobility	[Mpkm]	0.0	0.0	0.0	158000
Freight mobility	[Mtkm]	0.0	0.0	0.0	66000
Non energy	[GWh]	0.0	0.0	0.0	98436

Table 22: $\%_{\mathbf{Public}}$, $\%_{\mathbf{Rail}}$ and $\%_{\mathbf{Dhn}}$ for the Belgian energy system in the year 2015.

	Share [%]
$\%_{\mathbf{Public}}$	19.9% [15]
$\%_{\mathbf{Rail}}$	10.9% [15]
$\%_{\mathbf{Boat}}$	15.6% [15]
$\%_{\mathbf{Dhn}}$	2% [46]

The annual net electricity production shares for electricity production technologies is taken from [15, 46, 55]. The yearly shares of mobility and heating & CHP technologies per type of EUD (with respect to the main output) are reported in Tables 23-27.
The report [15] is used to fix the different shares of mobility supplied for public mobility (Table 23, [15]). For private mobility (Table 24, [15]), it is assumed that all biofuels ($\approx$3 TWh) is used for gasoline cars. The repartition between the different types of vehicles is estimated based on the number of vehicles in Belgium in 2015 (in millions: 2.11 gasoline, 3.46 diesel, 0.03 HEV, 0.02 NG and less for others) and their fuel efficiencies [16]. For all mobility technologies,

2010 efficiencies from [52] are used in the model verification.
For low and high temperature heat production (Tables 25, 26 and 27, [15, 46]), the electricity production from CHP plants is taken from [4]), while the input fuel and the heat production are estimated based on the efficiencies assumed for 2035.

Table 23: Yearly shares of public mobility technologies for the Belgian energy system in 2015.

	Share Mpkm [%]
Tram and Trolley Bus	4.5%
Diesel Bus and Coach	47%
Diesel HEV Bus and Coach	0.0%
NG Bus and Coach	10.0%
FC Bus and Coach	0.0%
Train/Metro	38.5%

Table 24: Yearly shares of private mobility technologies for the Belgian energy system in 2015.

	Share Mpkm [%]
Gasoline car	39.8%
Diesel car	59.2%
NG car	0.0%
HEV	0.0%
PHEV	0.0%
BEV	0.0%
FC car	0.0%

Table 25: Yearly shares of decentralized low temperature heat & CHP technologies for the Belgian energy system in 2015.

	Share heat [%]
HP	1.1%
Thermal HP	0.0%
CHP NG	0.7%
CHP Oil	0.1%
FC NG	0.0%
FC H_2	0.0%
Boiler NG	40.1%
Boiler Wood	3.4%
Boiler Oil	54.4%
Solar Th.	0.2%
Direct Elec.	0.0%

Table 26: Yearly shares of DHN low temperature heat & CHP technologies for the Belgian energy system in 2015.

	Share heat [%]
HP	4.4%
CHP NG	59.4%
CHP Wood	6.6%
CHP Waste	12.4%
Boiler NG	13.9%
Boiler Wood	0.0%
Boiler Oil	0.7%
Deep Geothermal	1%

Table 27: Yearly shares of industrial high temperature heat & CHP technologies for the Belgian energy system in 2015.

	Share heat [%]
CHP NG	8.6%
CHP Wood	0%
CHP Waste	2.8%
Boiler NG	0%
Boiler Wood	0%
Boiler Oil	20.6%
Boiler Coal	26.3%
Boiler Waste	0%
Direct Elec.	0%

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