energies

Article

Optimisation of Integrated Systems: The Potential of Power and Residential Heat Sectors Coupling in Decarbonisation Strategies

Julien Garcia Arenas [1,*], Patrick Hendrick [1] and Pierre Henneaux [2]

1 Department of Aero-Thermo-Mechanics, Université Libre de Bruxelles, F. D. Roosevelt Avenue 50, 1050 Brussels, Belgium; patrick.hendrick@ulb.be
2 Department of Bio-Electro- and Mechanical Systems, Université Libre de Bruxelles, F. D. Roosevelt Avenue 50, 1050 Brussels, Belgium; pierre.henneaux@ulb.be
* Correspondence: julien.garcia.arenas@ulb.be

Abstract: According to the objectives of the Paris Agreement on climate change, the European energy supply must be fully decarbonised by 2050. For the power sector, a massive deployment of decentralised renewable technologies will be required to provide carbon-free electricity. However, other energy-intensive sectors such as gas, heat, transport, and the industrial sectors are more challenging to decarbonise, since they rely mostly on liquid and gaseous fuels. Consequently, exploiting the synergies between energy vectors in an integrated, multi-energy system represents an opportunity for a cost-effective transition towards a carbon-free economy. The objective of this study is to provide insights on the coupling of power and residential heat supply systems in a centralised multi-energy system by developing a linear program that optimises the interactions between energy carriers such as electricity, heat, hydrogen, biomass, and methane to minimise the long-term investments in generation and storage assets. The tool was then applied to a case study for a carbon-neutral energy supply in the Brussels-Capital Region in 2050, and conclusions were drawn on the potential of sector coupling to determine the optimal supply system configuration. The conclusions were that the central planning and operation of a coupled system could induce an annual cost reduction of ownership and operation of more than 23% compared to the individual management of the power and residential heat sectors. The cost reduction reaches 30.9% if one further considers centralised, district-level storage and distribution of heat in district heating systems. Finally, it was concluded that the intermittent renewable energy infeed required along biomass to meet the total energy demand is significantly reduced in the optimal scenario. Indeed, the installed capacities of PV and wind onshore can be respectively reduced by 31.9% and 55.8%.

Keywords: multi-energy systems; linear programming; residential heat; sector coupling; long-term planning; energy supply

check for updates

Citation: Garcia Arenas, J.; Hendrick, P.; Henneaux, P. Optimisation of Integrated Systems: The Potential of Power and Residential Heat Sectors Coupling in Decarbonisation Strategies. *Energies* **2022**, *15*, 2638. https://doi.org/10.3390/en15072638

Academic Editors: AbuBakr S. Bahaj, Thomas Rushby, Philip Turner and Antonio Rosato

Received: 31 January 2022
Accepted: 24 March 2022
Published: 4 April 2022

1. Introduction

Europe (EU) is aiming to fully decarbonise its energy supply via a large electrification of the energy system, driven by a massive deployment of decentralised renewable technologies [1]. Although electrification is a viable decarbonisation strategy for low-grade heat production and light-duty heat transport, its feasibility is much more challenging for other energy end uses. Moreover, this deployment of intermittent renewable energy supply leads to a substantial increase in variability at different timescales in power supply, and introduces new challenges to ensure stability, reliability, and adequacy of the power system. The local peaks generated can be addressed by a smart energy management including demand response, and by the further deployment of technologies to match fluctuations in electricity demand and supply [2].

In this context, the coupling of energy sectors that are traditionally planned and operated independently is seen as an option to achieve a transition towards a net-zero greenhouse gas economy in a cost-effective way as it enables the exploitation of their interactions and synergies. The development of such integrated energy systems (or multi-energy systems, MES) is likely to lead to better technical, environmental, and economic performances compared to independent energy systems [3]. Indeed, the renewable electricity can be converted in other energy carriers such as heat or cooling, hydrogen (H_2), synthetic natural gas (SNG) or other advanced e-fuels by means of converter devices that are causing the interactions between energy systems. These allow energy system operators to arbitrarily shift between the electrical, chemical, and thermal states of energy.

In its communication on energy system integration to power a climate-neutral economy [4], the European Commission stresses that combined heat and power, the exchange of energy in smart district heating and cooling or energy communities, and the use of low-carbon fuels including H_2 are key concepts for energy system integration.

The long-term planning of MES plays an important role in the assessment of the impact of considering energy supply as an integrated whole on the flexibility of the power system as well as on the pollutants' emissions reduction potential and costs.

Indeed, defining cases studies and evaluating the best combination of energy vectors and technologies to simultaneously meet the different end-use services can provide insightful information on the technoeconomic effectiveness of decarbonisation strategies and pathways.

In this light, the objective of this paper is to provide views on the potential of coupling the power and residential heat sectors for the Brussels-Capital Region (BCR). Consequently, a linear programming (LP) optimisation framework is developed and applied as a case study to supply the energy needs of Brussels under zero-CO_2 emissions constraints. As a result, the equivalent annual cost of owning and operating of the integrated system as well as the levelised cost of energy (LCOE) of the energy supply are derived and discussed for four scenarios involving different levels of coupling.

2. Related Work

Mancarella [3] provided an overview of MES concepts. Overviews of MES modelling approaches were respectively provided by Mancarella et al. [5] and Kriechbaum et al. [6]. Specifically, Bloess et al. [7] identified state-of-the-art analytical model formulations for a flexible coupling of power and heat sectors using power-to-heat technologies, but with a lack of consideration of power-to-gas technologies. Gabrielli et al. [8] presented a novel mixed-integer linear programming (MILP) methodology that allows the simulation of multi-energy systems with seasonal storage considering a 1-year time horizon with hourly resolution, considering power-to-gas, but only heat pumps were studied for the coupling of power and heat and biomass was not considered. Liu et al. [9] proposed a long-term planning model for combined cooling, heating, and power systems considering energy storage and demand response, Dong et al. [10] developed a MILP optimisation–planning model of integrated energy systems based on a coupled combined cooling heating and power system, considering the planning and operation of power lines and gas pipelines; but both did not consider H_2, SNG, or biomass as energy vectors. A generic MILP framework for the optimisation of long-term investment planning of integrated urban energy systems, including gas cogeneration, EHP, and power-to-gas conversion is proposed by van Beuzekom et al. [11], without considering biomass and H_2 as additional energy vectors. The same observation applies to Martínez Ceseña et al. [12], who investigated the potential of multi-energy districts by applying an integrated electricity–heat–gas system model. Finally, Berger et al. [13] used modelling frameworks for the planning and operation of integrated energy systems to assess the role of power-to-gas, biomass and carbon-capture technologies in cross-sector decarbonisation strategies; however, the model does not explicitly consider the heat demand and, therefore, does not consider combined heat and power (CHP) and power-to-heat technologies.

In conclusion, there is still a need to explore, in a simple yet effective way, integrated systems configurations for decarbonisation strategies that simultaneously consider the coupling of heat, gas, and power systems with the use of electricity, NG, SNG, H_2, and biomass as energy vectors. This study aims to achieve this coupling by means of 10 converting units: biomass, NG or SNG and H_2 CHP units; biomass, NG or SNG, H_2 boilers; electric boilers and EHP units as power-to-heat technologies; and water electrolysis and methanation (METH) as power-to-gas technologies. Additionally, the study is extended with the comparison of individual and district-level technologies usage to determine an optimal configuration of the integrated power and residential heat supply system.

3. Problem Statement and Formulation

In this section, the interactions between the five energy vectors of the integrated system will be described with help of a schematic view of the MES given in Figure 1.

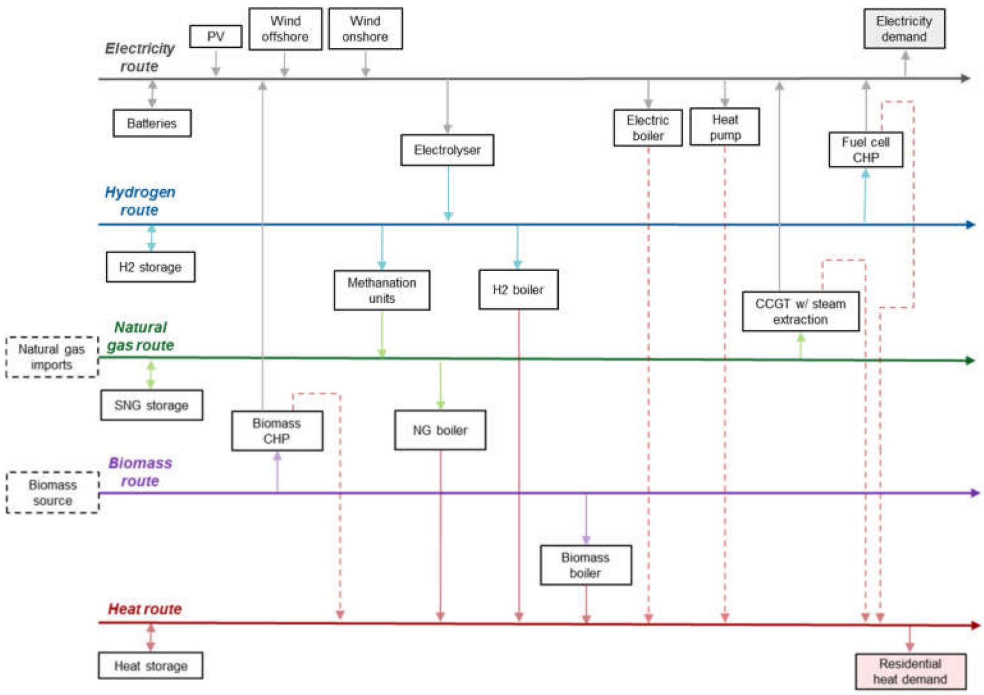

Figure 1. Schematic description of the multi-energy system.

As a second part, the modelling framework is provided with the presentation of the mathematical model.

3.1. The Multi-energy System

The proposed integrated system implies the coupling of five energy carrier routes, among which only one is a fossil fuel: electricity, hydrogen, natural gas (CH_4, NG), biomass, and heat.

The renewable energy infeed is coming from variable renewable energy sources (VRES) such as photovoltaics (PV), onshore wind (WON), and offshore wind (WOFF). The objective of the MES is to select and determine the optimal output of generating units to jointly meet the power and residential heat demands, while minimising the long-term investment and production costs of assets.

The coupling between these five energy routes is expected to drive the optimisation of energy management by means of converting technologies that allow to conveniently switch from one energy vector to another.

Along with storage assets for each energy vector except biomass, 10 converters are modelled: electrolysers (EL), H_2 fuel cells (FC) CHP, EHP, METH, CCGT, biomass CHP, and residential boilers. Four types of boilers are considered: classic NG boilers, electric boilers, biomass boilers, and H_2-ready boilers. CCGT and NG boilers can be either provided by NG or carbon-free SNG. The SNG is produced by combining H_2 with CO_2 following the Sabatier process in METH units. Note that NG and biomass are supposed fully available to be imported when needed. Finally, CO_2 involved in the Sabatier process is also assumed to be fully available, for example coming from the carbon capture of industrial processes.

3.2. Modelling Assumptions

The mathematical problem is formulated as a single-node LP using the GAMS modelling framework and is solved by the state-of-the-art IBM CPLEX solver.

The choice of a single-node LP allows consideration of the fact that all the above-presented technologies are fleets (or clusters) of numerous units operating in cascade at (or near) nominal efficiency. Moreover, the operational dynamics of individual units considered in unit-commitment (UC) formulation are not considered in the single-node formulation, alleviating the complexity of the model to optimise the MES with a 1-year simulation time interval with a reasonable solving time. Such typical operational constraints are the starting times and costs, the ramping up and down rates, the minimum loads, the minimum down times, or the eventual must-run times. Part-load efficiencies and variable CO_2 emission factors can also be considered.

Finally, with the target year of the BCR case study being 2050, it is expected that the considered technologies are sufficiently mature to be deployed with the projections of the techno-economic parameters presented in Table 1 Moreover, it is assumed that district heating (DH) infrastructure is widely available as well as the EU H_2 backbone infrastructure to fully enable the distribution of heat and H_2 for buildings.

Table 1. Main techno-economic parameters.

Technology Unit	Efficiency 1	HTP 1	Capex $\frac{MEUR}{MW}$	FOM $\frac{EUR}{MW}$	VOM $\frac{EUR}{MWh}$	Ref.
PV	-	-	0.24	3300	0	[14]
WON	-	-	0.96	11,340	0	[14]
WOFF	-	-	1.78	32,448	0	[14]
CCGT	0.60 [1]	0.45	0.8	26,000	4	[14]
NG boiler	0.99	-	0.1	19,100	0	[15]
H_2 boiler	0.98	-	0.2	7167	0	[16]
Electric boiler (indiv.)	1	-	0.773	7000	0	[15]
Electric boiler (district)	0.99	-	0.13	920	1	[14]
Biomass boiler (indiv.)	0.85	-	0.505	41,250	0	[15]
Biomass boiler (district)	0.90	-	0.285	5731	0	[15]
METH [2]	0.80	-	0.5	50,000	0	[17]
EHP (indiv.)	T.S.	-	1.25	58,750	0	[15]
EHP (district)	T.S.	-	0.57	2000	1.7	[14]
PEM FC	0.50	0.80	0.8	40,000	0	[14]
SO FC	0.60	0.62	0.8	40,000	0	[14]
SO EL	0.79	-	0.4	12,000	0	[18]
Biomass CHP	0.336	1.92	1.94	54,000	1.7	[15]
Salt cavern	0.99	-	0.0012 [3]	2.4×10^{-5}	1.2×10^{-5}	[19]
Battery (power)	97.5 (c)	-	0.06	540	0	[19]
Battery (energy)	98.5 (d)	-	0.035 [3]	0	1.6	[19]
Heat tanks (indiv.)	0.99	-	0.41 [3]	16,667	1.2	[15]
Heat tanks (district)	0.99	-	0.003 [3]	8.6	0	[19]

[1] This value is the electric efficiency of the CCGT; [2] for METH units, the values are equal to the 2030 projections from [15]; [3] the unit capex and FOM are expressed per MWh for these storage technologies. For battery technology, (c) and (d) are the charge and discharge efficiencies respectively.

3.3. LP Model Formulation

The following mathematical model is mostly inspired by the optimisation-based framework to tackle long-term centralised planning problems of MES, assuming perfect foresight and competition proposed by the department of electrical engineering and computer science from the University of Liège [13]. Note that when equations are adapted from other works, the associated references will be specifically indicated.

3.3.1. Sets

Four sets are introduced in the mathematical model: the simulation time interval I, containing the 8760 time steps; the set of energy carriers E = {elec, H_2, CH_4, biomass, heat}; the set of generating technologies G = {EL, FC, METH, CCGT, EHP, METH, boiler}; and the set of VRES technologies S = {PV, WON, WOFF}.

3.3.2. Converting Technologies

For each time step i in the simulation interval I, the operation and constraints of converting technologies are described as follows:

$$\forall\, i \in I,\ \forall\, e \in E,\ \forall\, g \in\ G$$

$$P(i)_g^{e\prime} = \eta_g^{e\prime} \times P(i)_g^{e} \tag{1}$$

$$P(i)_g^{e\prime} \leq\ K_g \tag{2}$$

where $P(i)_G^{e}$ and $P(i)_G^{e\prime}$ are respectively the consumption of the carrier e and the production of the carrier e', both expressed in MW. Equation (1) states that such technologies allow the switching from an energy vector into another considering the efficiency $\eta_T^{e\prime}$ to convert c into e'. In (2), K_g is the installed capacity of the technology generating c' that sets an upper value on its output.

Regarding EHP units, $\eta_g^{c\prime}$ is replaced by $COP(i)$, the coefficient of performance (COP) of such systems, a variable parameter that highly depends on the temperature of the heat source and sink through the year [7]. Although it is accepted to assume a constant, average value of the COP, several formulations are presented in [7] to compute $COP(i)$ as a function of these temperatures with different levels of complexity. Nevertheless, convenient time series representing the evolution of $COP(i)$ over the year for Belgium from the *When2Heat* dataset [20] were used as inputs of the simulation tool.

Finally, when considering the METH unit, CO_2 is combined to H_2 to produce SNG following the Sabatier process. The CO_2 mass inflow ($\dot{m}(i)_{METH}^{CO_2}$) to combine with H_2 for the reaction to occur is computed from $P(i)_{METH}^{CH_4}$ as follow:

$$\forall\, i \in I,$$

$$\dot{m}(i)_{METH}^{CO_2} = \frac{\varsigma^{CO_2/CH_4}}{HHV_{CH_4}} \times \frac{M_{CO_2}}{M_{CH_4}} \times P(i)_{METH}^{CH_4} \tag{3}$$

where ς^{CO_2/CH_4} is the ratio of the stoichiometric coefficients of CO_2 and O_2, M_{CO_2} and M_{CH_4} are respectively the molar mass of CO_2 and CH_4 in the Sabatier reaction, and HHV_{CH_4} is the higher heating value (HHV) of CH_4.

3.3.3. Cogeneration Technologies

For cogeneration technologies such as stationary CHP fuels cells and CCGT units with steam extraction (SE) turbines, additional equations are required for the heat co-produced. The introduction of the heat-to-power (HTP) ratio λ_{FC} is therefore carried out to describe the quantity of heat obtained per unit of generated power.

This ratio is linked to the electrical and thermal efficiencies of the unit (resp. η_{g*}^{elec} and η_{g*}^{heat} in a generic fashion via the following relation:

$$\forall\, g* \in\ G*,$$

$$\lambda_{g*} = \frac{\eta_{g*}^{heat}}{\eta_{g*}^{elec}} \tag{4}$$

where g^* is a cogeneration unit of the subset G^* comprising CCGT, FC and biomass CHP units. Consequently, knowing λ_{g*} and either one of the total heat or electricity conversion efficiency of the CHP plant, one can compute its power ($P(i)_{g*}^{elec}$) and heat ($P(i)_{g*}^{heat}$) outputs.

Starting with the formulation for the CHP units, the heat generated is formulated as in (4) with η_{FC}^{elec} and η_{FC}^{heat} being the electric and thermal efficiencies of the FC system:

$$\forall\, i \in I,\ \forall\, g* \ \in\ G*,$$

$$P(i)_{g*}^{heat} = \eta_{g*}^{heat} \times P(i)_{g*}^{H_2} = \lambda_{g*} \times P(i)_{g*}^{elec} \tag{5}$$

When considering CCGT systems with SE turbines, the modelling is adapted from [15] to allow the extraction of variable amounts of heat considering a power-loss factor (PLF) denoted β. This coefficient determines the loss of electricity generation to produce heat. Note that compared to back-pressure (BP) turbines, SE turbines are convenient for DH since the output water temperature can be adjusted [21].

$$\forall\, i \in I,$$

$$P(i)_{CCGT}^{heat} \leq\ \lambda_{CCGT} \times P(i)_{CCGT}^{elec} \tag{6}$$

$$P(i)_{CCGT}^{elec} \leq\ K_{CCGT} - \beta \times P(i)_{CCGT}^{heat} \tag{7}$$

Equation (6) is similar to (5) to compute the cogenerated heat power $P(i)_{CCGT}^{heat}$ using λ_{CCGT}, but one has to note that since it is an inequality, $P(i)_{CCGT}^{heat}$ may be variable and even null. Equation (7) introduces the fact that a loss of electrical power occurs in the CCGT if the heat power is nonzero at time step i.

3.3.4. Direct CO_2 Emissions

The CCGT and the NG boiler are units using a fossil fuel to produce energy, the direct CO_2 must then be accounted for as follows:

$$\forall\, i \in I,$$

$$\dot{m}(i)_{g**}^{CO_2} = \varepsilon_{g**} \times P(i)_{g**}^{CH_4} \tag{8}$$

where g^{**} is a CO_2-emitting unit of the subset G^{**} involving the CCGT and the NG boiler. For both these units, ε_{CH_4} is the specific CO_2 emissions factor of CH_4 and is set to 0.202 tonnes of CO_2 per MWh of CH_4 consumed. Note that the specific emissions of a power plant are not equal to the specific emissions of the fuel used, but the latter is chosen in this analysis as assumption.

3.3.5. Energy Storage

For each energy carrier $c \in C$, the set containing the four energy carriers, it is common to model the dynamics of its associated storage unit by updating its state of charge (SOC) for each time step, by considering self-discharge of the battery along with the charging and discharging efficiencies (resp. η_c^e and η_d^e) as follow $\forall\, i \in I, \forall\, e \in E$:

$$SOC(i)_s^e = (1 - \delta_s^e) \times SOC(i-1)_s^e + \eta_C^e \times P(i)_c^e - \frac{P(i)_d^e}{\eta_d^e} \tag{9}$$

$$SOC(i)_s \leq \kappa_s^e \tag{10}$$

Equation (9) shows that, to compute the current SOC of the technology s, the previous SOC is multiplied by a self-discharge coefficient δ_s^e, then the charging and discharging powers $P(i)_c^e$ and $P(i)_d^e$ are respectively added and subtracted considering their associated efficiencies.

Moreover, the installed energy capacity κ_s^e in (10) is setting a maximum value on the SOC of the storage technology s.

Note that, according to [18,22], it is acceptable to assume $\delta_s^{CH_4} = \delta_s^{H_2} = 0$, meaning that energy losses due to leakage in the NG and H_2 storage units can be considered negligible.

When considering batteries as electricity storage, additional equations are required to model its dynamics because one must make the distinction between its power and energy components. Indeed, the installed power capacity of the battery K_s^{elec} in (11) and (12) is used to constrain the power flowing in or out of the storage. Indeed, taking hydrogen storage as an illustrative example for the other storage technologies, the charging power is equal to the hydrogen power generated in the electrolyser, which is already constrained by K_{EL}.

$$P(i)_c^{elec} \leq K_s^{elec} \tag{11}$$

$$P(i)_d^{elec} \leq K_s^{elec} \tag{12}$$

$$\kappa_s^{elec} = \Gamma_s^{elec} \times K_s^{elec} \tag{13}$$

Equation (13) is deals with the interdependencies of the energy and power components of a battery using the coefficient Γ_s^{elec}. This coefficient is assumed to be equal to 4 in this study.

3.3.6. Carriers' Physics

The MES model comprises the five following single-node energy balance equations (resp. for electricity, H_2, CH_4, biomass and heat) that must be respected for each time step, one equation for each energy carrier. The left-hand side of these equations corresponds to the production of energy carrier while the right-hand side focuses on their consumption.

$$\forall\, i \in I$$

$$\begin{aligned} \sum^{v \in V} P(i)_v^{elec} + P(i)_{CCGT}^{elec} + P(i)_{FC}^{elec} + P(i)_{biomass\ CHP}^{elec} + P(i)_d^{elec} + P(i)_{NS}^{elec} \\ = P(i)_{demand}^{elec} + P(i)_{EL}^{elec} + P(i)_{EHP}^{elec} + P(i)_{elec\ boiler}^{elec} + P(i)_c^{elec} \\ + P(i)_{curt}^{elec} \end{aligned} \tag{14}$$

$$P(i)_{EL}^{H_2} + P(i)_d^{H_2} = P(i)_{FC}^{H_2} + P(i)_{H_2\ boiler}^{H_2} + P(i)_{METH}^{H_2} + P(i)_c^{H_2} \tag{15}$$

$$P(i)_{imports}^{CH_4} + P(i)_{METH}^{CH_4} + P(i)_d^{CH_4} = P(i)_{CCGT}^{CH_4} + P(i)_{NG\ boiler}^{CH_4} + P(i)_c^{CH_4} \tag{16}$$

$$P(i)_{source}^{biomass} = P(i)_{biomass\ CHP}^{biomass} + P(i)_{biomass\ boiler}^{biomass} \tag{17}$$

$$\begin{aligned} P(i)_{NG\ boiler}^{heat} + P(i)_{EHP}^{heat} + P(i)_{FC}^{heat} + P(i)_{CCGT}^{heat} + P(i)_{H_2\ boiler}^{heat} + P(i)_{biomass\ CHP}^{heat} \\ + P(i)_{biomass\ boiler}^{heat} + P(i)_{elec\ boiler}^{heat} + P(i)_d^{heat} \\ = P(i)_{demand}^{heat} + P(i)_c^{heat} \end{aligned} \tag{18}$$

In (14), $P(i)_v^{elec}$ is the power generation of the VRES technology $v \in V$ (PV, WON and WOFF), extracted from input time series (see Section 4.2.1). The terms $P(i)_{curt}^{elec}$ and $P(i)_{LS}^{elec}$ are introduced to allow eventual VRES curtailment or load shedding (LS), respectively.

3.3.7. Costs

The total cost of owning and operating an MES can be divided into two contributions, the total investment costs Ξ_{tot} and the total operating costs Θ_{tot}. Ξ_{tot} are determined by (19) considering the unit capex of the technology $t \in T$ and its installed capacity. As stated in (20), the five contributions to Θ_{tot} over the time interval I are the total fixed and variable operating costs (resp. FOM and VOM) for all the technologies, the total fuel costs C_{fuel}, the CO_2 emission costs C_{CO_2}, and the total cost of ENS.

$$\Xi_{tot} = \sum^{t \in T} capex_t \times K_t \tag{19}$$

$$\Theta_{tot} = \sum^{t \in T} \left(FOM_t \times K_t + VOM_t \times \sum^{i \in I} P(i)^e_t \right) + C_{fuel} + C_{CO_2} + C^{elec}_{NS} \tag{20}$$

C_{fuel} are estimated by multiplying the total power generation from CH_4 during the simulation by a constant unit cost of NG denoted ν_{CH_4}, set at 42.4 $\frac{\text{Eur}}{\text{MWh}}$ HHV imported [23]. The same process is applied with power generation from biomass with a constant unit cost $\nu_{biomass}$, set at 44.63 $\frac{\text{Eur}}{\text{MWh}}$ [24]. C_{CO_2} is determined by multiplying the difference of the total CO_2 emissions and the total amount of CO_2 that was converted in the methanation unit by a carbon price per tonne CO_2 emitted in the atmosphere ν_{CO_2}. The value of ν_{CO_2} is equal to 126 $\frac{\text{Eur}}{\text{t}}$, corresponding to the carbon tax projection for 2050 [23]. C^{elec}_{NS} is finally computed by the product of the total amount of curtailed electricity by the value of loss load ν_{voll}, set to 3000 $\frac{\text{EUR}}{\text{MWh}}$. This large value aims to discourage load shedding [13].

Note that, when considering a storage technology $s \in S$, κ^{elec}_s replaces K_t, and that $P(i)^e_t$ is substituted by the sum of $P(i)^e_c$ and $P(i)^e_d$.

Finally, the LCOE metric is computed in (21), adapted from the methodology for multi-energy systems presented in [25].

$$LCOE = \frac{\Xi_{tot} + \sum^{n \in N} \frac{\Theta_{tot}}{(1+D)^n}}{\sum^{n \in N} \frac{E_{demand}}{(1+D)^n}} \tag{21}$$

where E_{demand} is the total energy demand (electric and thermal) of the integrated system over the simulation time interval. Equation (21) represents the net present value (NPV) of the total costs over the economic lifetime N divided by the NPV of the energy produced over N.

3.3.8. Objective Function

An objective function represents any function that one wants to optimise over the time interval I. Regarding energy system simulations, the focus is to minimise the annual costs of owning and operating the MES, namely the sum of the total annualised CAPEX ($\Xi^{annualised}_{tot}$) and the total annual OPEX:

$$Minimise\left(Obj = \Xi^{annualised}_{tot} + \Theta_{tot}\right)$$

where $\Xi^{annualised}_{tot}$ is determined using (22), considering a discount rate D and an economic lifetime N of the project [26].

$$\Xi^{annualised}_{tot} = \frac{D}{1 - (1+D)^{-N}} \times \Xi_{tot} \tag{22}$$

The term multiplying Ξ_{tot} corresponds to the capital recovery factor.

4. Case Study

4.1. Description

The objective of the case study is to assess the impact of cross-sector coupling to decarbonise the power generation and residential heat supply for the city of Brussels in 2050, considering a minimisation of the annual cost of owning and operating the MES. Four scenarios are defined in the study and will be compared against each other to evaluate the potential of the integrated system under zero emissions constraints. For all cases, an additional constraint on VRES curtailment will be applied to ensure that the power system is sufficiently flexible to absorb at least 90% of the produced renewable infeed.

The first scenario discards any interactions between the power and heat supply routes, represented by dashed arrows in Figure 1. Consequently, no EHPs and electric boilers are deployed, and the FC and CCGT CHP units will only provide electricity. Biomass and SNG are expected to play a key role to produce carbon-free heat in this scenario. This scenario is considering Li-ion batteries and centralised solid oxide (SO) EL units with large scale H_2 storage using salt caverns. However, heat tanks, batteries, and proton-exchange membrane (PEM) FC, are considered at the individual, domestic level. The 7.975 TWh national underground NG storage located in Loenhout [27] is considered as storage unit for scenario 1 as well as for the other scenarios. Note that large-scale H_2 storage in salt caverns should be discarded since no such storage opportunities in Belgium are available to date [28], but it is assumed salt caverns connected to the future EU H_2 backbone will be available to store the produced H_2.

The second scenario considers the same technologies and unit sizes than the first scenario, with the difference that the cogeneration of electricity and heat in the biomass, CCGT and FC CHP units is fully enabled along with the use of individual electric boilers and residential air-source EHP.

Finally, the third and fourth scenario are similar to the first and second ones regarding the interaction between energy routes, but differs in the choices and size of the units to investigate the production of power and heat at a district level. Consequently, centralised SO FC units are deployed, implying a wide availability of DH with large-scale heat storage for heat distribution to be relevant at a larger scale in scenario 4. Similarly, domestic air-source EHP technology is replaced by district-level water-source EHP units, and individual electric and biomass boilers are replaced by larger units supplying heat in DH systems.

4.2. Input Data

The choice of the input data is crucial to contextualise the optimisation problem, and consequently has an impact on the accuracy of the results of the case studies.

Scalar inputs such as the techno-economic parameters' projections for technologies and energy carriers are described first, followed by the presentation and motivation of the energy consumption and VRES generation profiles.

4.2.1. VRES, Power and Heat Profiles

The profiles for the power the generation of VRES are extracted and normalised from the Belgian transmission system operator (TSO) Elia's online database for sun [29] and wind [30] energy time series. These time series are then adapted to the installed capacities of the VRES technologies determined by the optimiser.

In a similar fashion, national historical profiles coming from Elia [31] and the *When2Heat* database [20] are adapted to fit to the annual power and residential heat energy needs of the BCR. The required supply is respectively 4554 GWh of electricity and 3109 GWh of heat per year, according to [32] and considering that 96.9% of the fossil fuel consumption of the EU residential sector is for space- and water-heating purposes [33]. Moreover, the heat demand is determined assuming that, with a renovation rate of 3%, the energy consumption in the Belgian building sector will decrease of almost 40% by 2050 [34]. The resulting estimated electric and thermal demand profiles are presented in Figure 2.

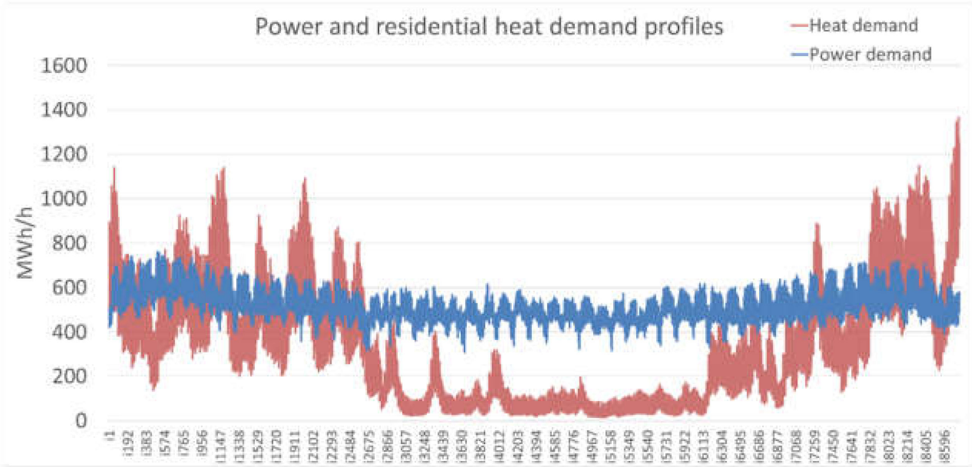

Figure 2. Estimated annual profiles for the power and residential heat demands for the BCR in 2050. *X*-axis units are the time steps, representing the hours of the year.

4.2.2. Techno-Economic Parameters

The 2050 projections of the conversion efficiency, unit capex, FOM, and VOM parameters are presented in Table 2. for all considered technologies. The unit capex used for the calculations accounts for equipment, installation, and grid connection costs.

Table 2. Results of the case study: annual cost of owning and operating the MES per scenario.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Annualised cost (MEUR)	533.51	409.41	482.10	368.50
LCOE ($\frac{EUR}{MW}$)	69.62	53.43	62.91	48.09

In addition, following the common pan-European discounting methodology [35], the discount rate D is set to 4% and the economic lifetime N to 25 years with no residual value.

Furthermore, one assumes that the HHV of the obtained SNG is equal to the one of NG, allowing to assume a uniform calorific value of the gas mixture flowing in the natural gas transport infrastructure equal to 15.4 $\frac{MWh}{t}$.

Finally, note that to compute the FOM of salt caverns, the interdependency factor $\Gamma_s^{H_2}$ is set to 1000 [25]. Moreover, the efficiency is not used for VRES technologies since power values are coming from input time series. The COP value for EHP units is coming from time series as well.

5. Results and Conclusions

The results of the case study are presented in Figure 3, Tables 2 and 3. Figure 3 and Table 3 present the annual cost of owning and operating the MES for each scenario, while Table 4 presents the installed capacities of the technologies per scenario.

Under the assumptions of this work, one observes from Table 3 and Figure 3 that the total costs decrease when sector coupling is enabled. Indeed, when comparing scenarios 1 and 2 against 3 and 4, the total annual costs decrease by 23.2% and 23.6%, respectively. This holds true when comparing the LCOE of these scenarios. The use of district-level units for sector coupling also reduces the total costs as well, compared to the use of individual units. Indeed, one observes a cost reduction of 9.6% and 10.2%, respectively, when comparing scenarios 1 and 3 against 2 and 4. Enabling both coupling between power and residential heat sectors and the use of district-level technologies induces a cost reduction of 30.9% for the energy supply of Brussels in 2050, with an LCOE equal to

48.09 $\frac{\text{EUR}}{\text{MWh}}$. However, one must account for the price and availability of hydrogen and heat distribution infrastructures.

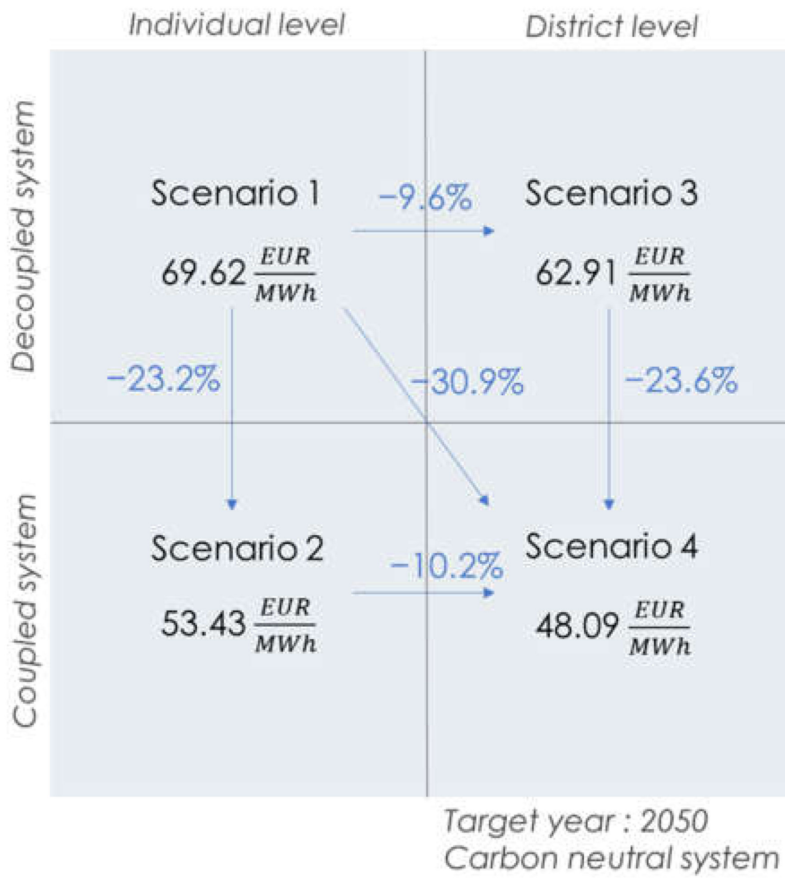

Figure 3. LCOE comparison for scenarios 1 to 4 of the case study.

Table 3. Results of the case study: installed capacities for scenarios 1 to 4.

Installed Capacity (MW)	Scenario 1	Scenario 2	Scenario 3	Scenario 4
PV	5340.62	3862.58	4636.65	3637.05
WON	1738.62	953.66	1448.94	768.35
WOFF	0	0	0	0
CCGT	400.95	234.62	351.33	182.88
NG boiler	160.07	0	0	0
H_2 boiler	622.22	405.04	173.31	0
Electric boiler	0	172.23	0	242.27
Biomass boiler	582.90	0	705.93	0
METH	190.06	52.92	110.28	32.91
EHP	0	0	0	0
FC	0	0	0	0
EL	530.35	141.24	385.33	52.08
Biomass CHP	18.44	355.39	103.88	337.98
Battery (power)	2287.26	1754.83	1976.30	1511.76
Battery (energy)	9149.05 [1]	7019.33 [1]	7905.22 [1]	6047.06 [1]
H_2 storage	41,598.40 [1]	35,557.40 [1]	28,178.00 [1]	0 [1]
Heat storage	0 [1]	0 [1]	14,317.70 [1]	49,483.30 [1]

[1] The installed capacities of storage technologies are expressed in MWh. Note that, for each scenario, no imports of NG were reported, only SNG is used in the CCGT and the NG boilers.

Table 4. Results of the case study: installed capacities for scenarios 5 to 8.

Installed Capacity (MW)	Scenario 5	Scenario 6	Scenario 7	Scenario 8
PV	7507.43	5584.73	7053.67	4766.20
WON	2440.65	2118.93	2586.64	1881.88
WOFF	0	0	0	0
CCGT	323.86	308.98	334.07	330.30
NG boiler	648.59	321.44	402.11	0
H_2 boiler	716.60	353.75	562.11	0
METH	428.58	239.74	382.09	171.83
EHP	0	475.01	0	720.07
FC	0	94.94	0	108.79
EL	1008.47	497.92	1038.14	330.47
Battery (power)	3138.26	2192.48	2875.19	1862.62
Battery (energy)	12,553.10 [1]	8721.20 [1]	11,500.80 [1]	7450.47 [1]
H_2 storage	89,241.10 [1]	11,802.00 [1]	157,566.00 [1]	75,406.30 [1]
Heat storage	0 [1]	0 [1]	17,603.50 [1]	26,305.20 [1]

[1] The installed capacities of storage technologies are expressed in MWh. Note that, for each scenario, no imports of NG were reported, only SNG is used in the CCGT and the NG boilers.

The scenario achieving the lowest cost of energy supply is scenario 4, with an LCOE of 48.09 EUR/MWh. The associated model configuration is involving the use of biomass and SNG CHP units and electric boilers, all supplying heat via DH. In this scenario, H_2 production via water electrolysis is directly converted into SNG, thereby excluding its use in FC CHP and boilers. No storage of H_2 is considered by the optimiser, only seasonal storage of SNG. Finally, battery and heat storage are also selected to reduce the annual costs in the last scenario.

From Table 3, one understands that amongst the technologies and energy vectors considered in this study, electricity storage, biomass and SNG would play a key role for a carbon neutral energy supply in cities, with an extensive use of batteries, biomass and NG CHP technologies in every scenario. It is also reported that, for each scenario, no NG was imported to the system, meaning that only SNG was used. On the other hand, EHP and FC technologies were never used in the four scenarios, suggesting that these are not competitive compared to the other technologies, even if considering the 2050 technoeconomic data projections. Note that, although not included in this work, the potential of other hydrogen CHP technologies such as H_2 turbines or H_2 internal combustion engine should be studied according to the authors.

Additionally, it is shown in scenario 1 that when no coupling and district-level technologies are considered, NG and H_2 boilers are preferred compared to biomass and electric boilers. Moreover, while NG boilers are not considered in scenarios 2, 3 and 4, electric boilers are only chosen by the optimiser when district-level units are enabled, and H_2 boilers are abandoned when both coupling and district-level technologies are enabled in scenario 4. This is certainly due to the very cheap cost of electric boilers technology for DH purposes.

A further analysis of the technology mixes per scenario in Table 3 highlights that sector coupling with the deployment of district-level technologies has the potential to significantly reduce the VRES infeed required to supply cities. In fact, the installed capacities of PV and Wind onshore are reduced by 31.9% and 55.8%, respectively, when comparing scenario 1 with scenario 4. Note that offshore wind turbine technology is never selected by the optimiser, certainly due its larger cost compared to onshore wind technology and since the maximum installed capacities of PV and WON are not outreached. Furthermore, the use of H_2 and SNG is significantly reduced from scenario 1 to scenario 4 as well, suggesting that heat cogeneration and distribution of heat in DH systems with heat storage has the potential to reduce the need for e-fuels for residential heating supply in cities. Indeed, installed capacities of EL and METH units in the last scenario are roughly divided by 10 and 6, respectively, compared to the first scenario.

Focusing on biomass, one observes that the use of biomass CHP is maximised when heat is recovered for DH purposes, since biomass CHP capacity increase while biomass boilers are put aside and the installed capacities of H_2 boilers and SNG CCGT decrease when allowing sector coupling (scenario 2 compared to scenario 1). Finally, the use of biomass seems promising for the carbon-free supply of cities because it is considered as a net zero CO_2 emissions fuel, which gives a clear advantage compared to the expensive and less efficient production of e-fuels such has H_2 and SNG.

It is important to note that the multi-energy system of this case study is proposed regardless of the potential future ambitions of the Brussels authorities regarding energy efficiency and local emissions of pollutants. Therefore, in 2050, EHP technologies might be preferred to resistive heaters to reduce the power-to-heat induced peak electricity use [36]. In terms of urban air quality, some biomass combustion technologies might be prohibited on the BCR territory since solid biomass is not included in the medium-term strategy and will likely be subject to strong environmental requirements and air quality standards [36].

To ensure a replicability for the BRC, the 4 scenarios of the case study are studied again, excluding the use of biomass technologies as well as electric boilers. Consequently, scenarios 5 to 8 are presented hereafter in Figure 4 and Table 4, following the same methodology than for scenarios 1 to 4.

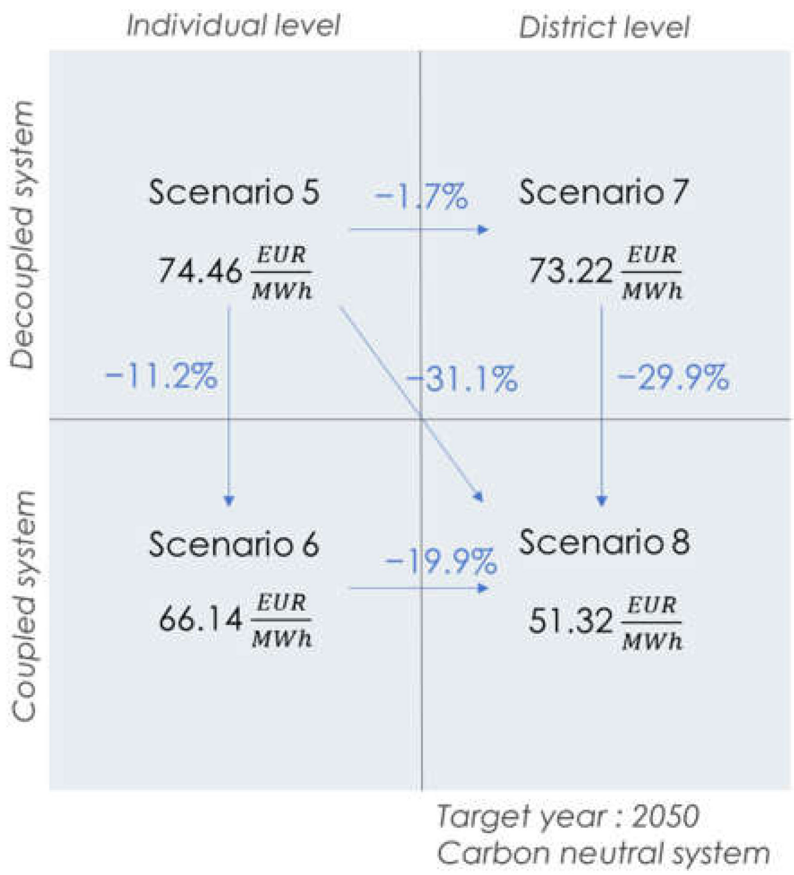

Figure 4. LCOE comparison for scenarios 5 to 8 of the case study.

From Figure 4, one observes that the best-case scenario is scenario 8, with a LCOE equal to 51.32 $\frac{\text{EUR}}{\text{MWh}}$ for the energy supply. In comparison with scenario 5, the best-case scenario of the case study including biomass and electric boilers, the annual costs increased by 6.3%. Consequently, if efficiency and strict air quality standards are prominent in the decarbonisation strategy, the total annual costs for the energy supply are expected to increase since more hydrogen is required to replace the use of solid biomass, inducing an increase in PV and EL capacities in scenarios 5 to 8. On the other hand, local emissions of pollutants for power and residential heat supply are avoided and the induced peak due to power-to-heat technologies is reduced by more than 30% (244.7 MW peak due to electric boilers in scenario 4 opposed to 165.5 MW peak due to EHP units in scenario 8).

Moreover, the conclusions regarding the cost reduction potential when applying sector coupling and considering district-level technologies are equivalent for both sets of scenarios, with a LCOE reduced by 31.1% for the energy supply in scenario 8 compared to scenario 5.

Focusing on the technology mixes presented in Table 4, the required installed capacity of PV is reduced by 32.43% when coupling is enabled with DH (scenario 5 compared to scenario 8). In scenario 6, when power-to-heat interactions are enabled, massive investments in individual EHPs are observed (and in FC to a lesser extend), with the consequence to reduce the use of H_2 and SNG in residential boilers since one notes an important reduction in METH and NG boilers capacities in scenario 6 compared to scenario 5. Quite surprisingly, the capacities of NG and H_2 boilers is null in the last scenario, totally replaced by FC and CCGT in cogeneration mode along with EHP units. These technologies again alleviate the production and use of SNG, with installed capacities of METH units divided by 2.22 with regard to scenario 5. The capacity of EL technology is substantially reduced as well since les H_2 is required to produce SNG and heat. It is finally worth noting that storage of each energy vector is a key element to achieve a carbon neutral energy supply, with heat storage being particularly important in scenario 8 where heat is produced at district-level and distributed via DH.

6. Summary

This study was divided into two main parts, with the first part being the elaboration of the mathematical model to describe the interactions between five energy vectors (electricity, heat, methane, biomass and hydrogen) in a multi-energy system, with the objective to minimise the long-term investments in generation and storage assets for the power and residential heat supply in cities.

The second part consists of the application of the mathematical model to a case study for the carbon-neutral energy supply of the BCR in 2050, with a collection of the input data of the model and the definition of four scenarios to be compared to evaluate the impact of power and residential heat sector coupling in decarbonisation strategies. The data collection concerns the input time series representing the power and residential heat demands of Brussels, the Belgian normalised VRES production profiles (PV, wind onshore and wind offshore) along with the 2050 projections of the technoeconomic parameters of each technology and energy vector involved in the mathematical model. Other time series such as the annual coefficient of performance profiles of the selected electric heat pump technologies are included. Regarding the analysed scenarios of the case study, the first scenario is described as the one without any coupling between power and heat supply: power-to-heat technologies as well as cogeneration of power and heat are discarded. Moreover, individual scale technologies are considered, without distribution of heat in district heating. The second scenario enables the previously mentioned interaction between power and heat supply but the technologies are kept at an individual level. The third and fourth scenarios are similar to the first and second ones regarding the interaction between energy routes, but differ in the choices and size of the units to investigate the production of power and heat at a district level.

Finally, the resulting optimised economic performances (annualised cost and LCOE of energy supply) and technology mixes are presented and discussed for the four scenarios, giving insights on the potential for power and residential heat sector coupling in decarbonisation strategies. To ensure a replicability for the BRC, 4 additional scenarios are studied for an energy supply excluding the use of biomass technologies as well as electric boilers to fit the long-term efficiency and urban air quality objectives of the Brussels administration.

Author Contributions: Conceptualization, J.G.A.; methodology, J.G.A. and P.H. (Pierre Henneaux); software, J.G.A.; validation, P.H. (Patrick Hendrick) and P.H. (Pierre Henneaux); formal analysis, J.G.A.; investigation, J.G.A.; resources, P.H. (Pierre Henneaux); data curation, P.H. (Pierre Henneaux); writing—original draft preparation, J.G.A.; writing—review and editing, J.G.A.; visualization, J.G.A.; supervision, P.H. (Patrick Hendrick) and P.H. (Pierre Henneaux); project administration, P.H. (Patrick Hendrick); funding acquisition, P.H. (Patrick Hendrick). All authors have read and agreed to the published version of the manuscript.

Funding: This work has been done with the support of the research project EPOC 2030–2050, funded by the FPS Economy and Energy (Energy Transition Funds) of the Federal Government of Belgium.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: All data used are referenced from public sources within the article.

Conflicts of Interest: The authors declare no conflict of interest. The funders had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript, or in the decision to publish the results.

References

1. European Commission. A Clean Planet for All: A European Strategic Long-Term Vision for a Prosperous, Modern, Competitive and Climate Neutral Economy. November 2018. Available online: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52018DC0773 (accessed on 31 July 2021).
2. European Commission. Powering a Climate-Neutral Economy: An EU Strategy for Energy System Integration. July 2020. Available online: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=COM:2020:299:FIN (accessed on 31 July 2021).
3. Mancarella, P. MES (multi-energy systems): An overview of concepts and evaluation models. *Energy* **2014**, *65*, 1–17. [CrossRef]
4. Van Nuffel, L.; Dedecca, J.G.; Smit, T.; Rademaekers, K. Sector coupling: How can it be enhanced in the EU to foster grid stability and decarbonise? November 2018. Available online: https://www.europarl.europa.eu/thinktank/en/document.html?reference=IPOL_STU(2018)626091 (accessed on 31 July 2021).
5. Mancarella, P.; Andersson, G.; Peças-Lopes, J.A.; Bell, K.R.W. Modelling of Integrated Multi-Energy Systems: Drivers, Requirements, and Opportunities. In Proceedings of the Power Systems Computation Conference (PSCC), Genoa, Italy, 20 June–24 July 2020. [CrossRef]
6. Kriechbaum, L.; Sheiber, G.; Kienberger, T. Grid-based multi-energy systems—Modelling, assessment, open-source modelling frameworks and challenges. *Energ. Sustain. Soc.* **2015**, *8*, 35. [CrossRef]
7. Bloess, A.; Schill, W.P.; Zerrahn, A. Power-to-heat for renewable energy integration: A review of technologies, modeling approaches, and flexibility potentials. *Appl. Energy* **2018**, *202*, 1611–1626. [CrossRef]
8. Gabrielli, P.; Gazzani, M.; Martelli, E.; Mazzotti, M. Optimal design of multi-energy systems with seasonal storage. *Appl. Energy* **2018**, *219*, 408–424. [CrossRef]
9. Liu, Z.; Zhao, Y.; Wang, X. Long-term economic planning of combined cooling heating and power systems considering energy storage and demand response. *Appl. Energy* **2020**, *279*, 115819. [CrossRef]
10. Dong, X.; Quan, C.; Jiang, T. Optimal Planning of Integrated Energy Systems Based on Coupled CCHP. *Energies* **2018**, *11*, 2621. [CrossRef]
11. Van Beuzekom, I.; Hodge, B.-M.; Slootweg, H. Framework for optimization of long-term, multi-period investment planning of integrated urban energy systems. *Appl. Energy* **2021**, *292*, 11–39. [CrossRef]
12. Ceseña, E.A.M.; Loukarakis, E.; Good, N.; Mancarella, P. Integrated Electricity–Heat–Gas Systems: Techno–Economic Modeling, Optimization, and Application to Multi-energy Districts. *IEEE* **2020**, *108*, 1392–1410. [CrossRef]
13. Berger, M.; Radu, D.; Fonteneau, R.; Deschuyteneer, T.; Detienne, G.; Ernst, D. The role of power-to-gas and carbon capture technologies in cross-sector decarbonisation strategies. *Electr. Power Syst. Res.* **2020**, *180*, 106039. [CrossRef]
14. Danish Energy Agency, and Energinet. Technology data: Generation of electricity and district heating. April 2020. Available online: https://ens.dk/sites/ens.dk/files/Statistik/technology_data_catalogue_for_el_and_dh_-_0009.pdf (accessed on 21 March 2021).
15. Danish Energy Agency, and Energinet. Technology data: Heating installations. June 2021. Available online: https://ens.dk/sites/ens.dk/files/Analyser/technology_data_catalogue_for_individual_heating_installations.pdf (accessed on 21 March 2021).
16. Savu, L.M.; Amalia, M.A.; Remus, S.E.; Vasile, A.M.; Tabita, N.D. BatHyBuild Study: Use of Hydrogen in Buildings. April 2021. Available online: https://www.waterstofnet.eu/_asset/_public/BatHyBuild/Hydrogen-use-in-builings-BatHyBuild-29042021.pdf (accessed on 31 July 2021).
17. ADEME. Etude portant sur l'hydrogène et la méthanation comme procédé de valorisation de l'électricité excédentaire. September 2014. Available online: https://www.ademe.fr/sites/default/files/assets/documents/etude_powertogas_ademe-grdf-grtgaz.pdf (accessed on 21 March 2021).

18. Danish Energy Agency, and Energinet. Technology data: Renewable fuels. April 2021. Available online: https://ens.dk/sites/ens.dk/files/Analyser/technology_data_for_renewable_fuels.pdf (accessed on 21 March 2021).
19. Danish Energy Agency, and Energinet. Technology data: Energy Storage. January 2020. Available online: https://ens.dk/sites/ens.dk/files/Analyser/technology_data_catalogue_for_energy_storage.pdf (accessed on 21 March 2021).
20. Ruhnau, O.; Hirth, L.; Praktiknjo, A. Time series of heat demand and heat pump efficiency for energy system modeling. *Sci. Data* **2019**, *6*, 189. [CrossRef]
21. Kavvadias, K.; Jimenez Navarro, J.P.; Zucker, A.; Quoilin, S. *Case Study on the Impact of Cogeneration and Thermal Storage on the Flexibility of the Power System*; Publication Office of the European Union: Luxembourg, 2018.
22. Belderbos, A.; Valkaert, T.; Bruninx, K.; Delarue, E.; D'Haeseleer, W. Facilitating renewables and power-to-gas via integrated electrical power-gas system scheduling. *Appl. Energy* **2020**, *275*, 115082. [CrossRef]
23. ENTSO-E. Maps and Data, TYNDP 2018 Storage Projects. Available online: http://tyndp.entsoe.eu/maps-data/ (accessed on 31 July 2021).
24. Duić, N.; Stefanić, N.; Lulić, Z.; Krajacić, G.; Puksec, T.; Novosel, T. Heat roadmap Europe 2050 Deliverable 6.1: EU28 fuel prices for 2015, 2030 and 2050. November 2017. Available online: https://heatroadmap.eu/wp-content/uploads/2020/01/HRE4_D6.1-Future-fuel-price-review.pdf (accessed on 21 March 2021).
25. Stevanato, N.; Rinaldi, L.; Pistolese, S.; Subieta, S.L.B.; Quoilin, S.; Colombo, E. Modeling of a Village-Scale Multi-Energy System for the Integrated Supply of Electric and Thermal Energy. *Appl. Sci.* **2020**, *10*, 7445. [CrossRef]
26. LEAP help. AnnualizedCost. Available online: https://www.energycommunity.org/WebHelpPro/LEAP.htm#t=Concepts%2FIntroduction.htm (accessed on 31 January 2021).
27. SPF Economie. Monitoring report on the security of supply on the Belgian natural gas market. 2014. Available online: https://economie.fgov.be/nl/file/4057/download?token=z_UcXg5h (accessed on 31 July 2021).
28. Undertaking, H.J.; Gérard, F.; van Nuffel, L.; Smit, T.; Yearwood, J.; Černý, O.; Michalski, J.; Altmann, M. Belgium—Opportunities for hydrogen energy technologies considering the national energy & climate plans. July 2020. Available online: https://www.fch.europa.eu/sites/default/files/file_attach/Brochure%20FCH%20Belgium%20%28ID%209473032%29.pdf (accessed on 31 July 2021).
29. Elia. Solar-PV power forecasting for Belgium. Available online: https://www.elia.be/fr/donnees-de-reseau/production/production-photovoltaique (accessed on 31 July 2021).
30. Elia. Wind forecast. Available online: https://www.elia.be/fr/donnees-de-reseau/production/donnees-de-production-eolienne (accessed on 31 July 2021).
31. Elia. Total load on the Belgian grid (Historical data—Up to day-1). Available online: https://opendata.elia.be/explore/dataset/ods001/information/ (accessed on 31 July 2021).
32. IBSA. Energie, Tableaux—2021/05. Available online: https://ibsa.brussels/themes/environnement-et-energie/energie (accessed on 31 July 2021).
33. Eurostat. Energy Consumption in Households—Statistics Explained. Available online: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Energy_consumption_in_households#Energy_consumption_in_households_by_type_of_end-use (accessed on 31 July 2021).
34. FPS Public Health, and DG Environment. Scenarios for a climate neutral Belgium by 2050. May 2021. Available online: https://climat.be/doc/climate-neutral-belgium-by-2050-report.pdf (accessed on 31 July 2021).
35. ENTSO-E. 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects (Draft version). January 2020. Available online: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/2020-01-28_3rd_CBA_Guidleine_Draft.pdf (accessed on 31 July 2021).
36. Marenne, Y.; Lempereur, A.; Tamignaux, F. Potential for heating and cooling efficiency in the Brussels-Capital Region. March 2021. Available online: https://energy.ec.europa.eu/system/files/2021-10/be-bru_ca_2020_en.pdf (accessed on 21 July 2021).