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Potential advantages in heat and power production when biogas is collected from several digesters using dedicated pipelines - A case study in the "Province of West-Flanders" (Belgium)

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A B S T R A C T

In the case study "West-Flanders" costs of electricity and heat production are estimated if a dedicated biogas grid using pipelines would be implemented to centralize energy production in a region. Heat may not be used effectively at digester sites, *e.g.* because of a change in treatment of digestate. A large scale centralized combined heat and power (CHP) engine can produce additional electrical power at a hub, *i.e.* central collection point, and has lower specific costs compared to decentralized CHPs at digester sites. A biogas transport model is used to calculate transport costs in a grid. These costs, partly balanced by a scale advantage in CHP costs, are attributed to the additional electrical energy (80%) and heat (20%) produced. If the hub is at a digester site, costs of additional electricity can be as low as 4.0 €ct kWh_e^{-1} and are in many cases below 12 €ct kWh_e^{-1}, *i.e.* in the same order of magnitude or lower than costs of electricity from biogas produced using separate CHPs at the different digester sites; costs of heat at the hub show to be lower than 1 €ct kWh_{th}^{-1} assuming an effective heat use of 50%. In case a hub is situated at a location with high potential heat demand, *i.e.* a heat sink, transport of biogas from one digester only to a central located hub can provide 3.4 MW_{th} of heat at 1.95 €ct kWh_{th}^{-1}. For such a centrally located hub additional electrical energy costs show to be slightly higher, but with three or more digesters these costs are lower than 20 €ct kWh_e^{-1} and heat costs are around 0.5 €ct kWh_{th}^{-1}. With a centralized hub more renewable energy is produced, *i.e.* a more efficient use of biomass feedstock. It is concluded that costs for additional electricity and heat can be at a competing level and scale advantages in a CHP can be a driver to collect biogas at a hub using a biogas grid.

1. Introduction

Biomass is seen as an important renewable energy source to attain the European 20-20-20 targets. Also in Belgium biomass plays this role in the renewable energy production. The Belgian 2020 renewable energy targets are translated into federal and regional targets, thereby encouraging activities at decentralized level. In the Flemish Region (Vlaanderen) biogas was used to produce 10.1% of renewable electricity, and 14.6% of renewable heat in 2015; totals were respectively 7449 GWh and 21.694 TJ in 2015. Electricity and heat production from biogas increased with 8.2% and 8.4% respectively as compared to 2014 [1].

With an increased amount of renewable energy from solar and wind, also the need for a more flexible energy system arises and storage of energy is seen as one of the solutions. Biogas will also be part of the solution as it has two advantage compared to other renewable energies, (1) energy produced with a biogas CHP is non-intermediate and (2) biogas can be stored relatively easy in pressureless containers or in pressurized cylinders. Furthermore, the implementation of a biogas grid adds to storage capacity as line-pack storage in the grid may also be used [2]. The amount of line-pack storage depends on among others, the volume within the

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pipelines of the biogas grid and the difference between maximum allowable pressure and transport pressure [3]. Line-pack storage costs and volume in a regional biogas grid are estimated in Ref. [4] based on a model. Important to evaluate the specific advantages of such a biogas grid is to have good insight in biogas production costs, developments in biogas/natural gas combined heat and power (CHP) installations, and biogas grid costs.

Several authors investigated the biogas production cost. Among authors the attribution of costs to biogas production differs, *e.g.* the income of digestate sales could be treated separately [5,6], but also could be partly allocated to the production of substrate [7]. Several authors compare biogas projects by presenting the net present value (NPV) results for a biogas project as a whole, whereby the project boundaries determine what costs and income are included [8–10]. Biogas production costs are estimated by J. Bekkering et al. (2010) between 0.29 €m^{-3} and 0.31 €m^{-3} biogas for an energy crop with manure mix, depending on the digester scale. These costs include biomass, operation and maintenance (O&M) and investment costs. For manure the authors assumed a negative price to accommodate for avoided disposal costs [7]. In a paper by Riva et al. (2014) biogas production costs are presented for three plants that differ in scale, input mixture and technology. Biogas production costs are estimated between 0.265 €m^{-3} and 0.354 €m^{-3}. Included in these costs are organic material supply costs, O&M costs and depreciation charges [11]. According to Schievano et al. (2015) biogas production costs depend on the type of biomass and scale of the installation. In their study three different crop types were taken into account. For a 1 MW_e plant costs range from 0.270 €m^{-3} up to 0.424 €m^{-3}. Whereas for a 0.5 MW_e plant the costs range from 0.372 €m^{-3} to 0.526 €m^{-3}. Costs presented by these authors for biogas from maize match with the result of Bekkering et al. [7,12].

Information on the use of biogas in a CHP unit is provided in a paper by Lantz (2010) in which two CHP technologies are presented. The author shows a techno-economic analysis of an energy production chain based on digestion of manure in Sweden. He compares sparkplug ignition engines with compression ignition engines in three hypothetical cases, the largest has a scale of 6 GWh a^{-1}. The scale has a large influence on the economic feasibility, as has the price and level of utilisation of heat [13]. Goulding et al. discuss two biogas utilisation technologies, *i.e.* biogas to CHP and biomethane as a transport fuel. The biomass source is limited to agricultural crops in Ireland and the used scales range from 50 ha to 350 ha with several crop rotation schemes. The conclusions indicate that biomethane as a transport fuel can compete with fossil fuels. For biogas to CHP the authors concluded that “unless a heat demand can be found, such facilities will remain financially unfeasible” [14]. Amiri et al. (2013) show the introduction of a biogas CHP plant in an energy system at city level considering two biogas plants in a case study. In the base case biogas is upgraded to serve as vehicle fuel and part of the biogas is used to produce heat needed in the digesters. Based on the model they conclude that the implementation of a CHP is profitable, that there is no need for external heat and electricity and that any surplus of heat and electricity can be sold [15]. Hers et al. (2015) consider natural gas CHP installations at large scales, *i.e.* more than 20 MW_{th}. They propose a method to decide on reinvestment either in a new or retrofit CHP. The authors explain that a (natural gas) CHP can be operated in two ways, either “heat driven” or “electricity driven”. The former aiming at supplying a fixed baseload of heat or following heat demand, while the other produces matching the electricity market. In the analysis they show that “electricity driven” is in most cases to be preferred from a financial point of view [16]. Ghadimi et al. (2014) developed a model to integrate sizing and the operational strategy of a natural gas CHP using an industrial case study. Operational strategies considered are base load operation, electrical load following, thermal load following and optimization strategies minimizing surplus energy or operational costs. The model predicts that a CHP can improve energy efficiency with reduced costs [17].

Supported by the above literature study it can be concluded that biogas collection from several digesters to a hub could support the efficient use of renewable energy from biomass. At a hub, generally a larger volume of biogas induces a scale advantage for the end user through a cost reduction [18–20]. A large improvement of overall energy efficiency can be achieved in a biogas CHP engine when heat generation and heat demand are matched. Efficient use of heat at agricultural digester sites is often accomplished in the processing of digestate. Heat is used to dry the digestate to reduce transport costs, as the digestate is often transported abroad due to overproduction of manure in the region [21]. However other valorisation options for the digestate are under investigation [22]. These options do not require the use of heat in the same way, leaving a potential renewable heat source unused. In that situation it is beneficial to study the potential of using a biogas hub as an alternative to optimally use the biogas. By transporting the biogas to a place with an appropriate heat demand, *e.g.* a town with district heating, the biogas can be used to its full potential. In a recent paper a biogas transport model using a pipeline grid [18] was introduced. Costs and energy use of biogas transport were presented for two grid types. In a star lay-out, digesters are individually connected by a pipeline to the hub. In a fishbone lay-out biogas from several digesters is collected through pipeline segments into a larger common pipeline. This common pipeline connects to the hub. Based on a theoretical case study, *i.e.* the digesters follow a symmetric, regular pattern and the digesters have equal scales, the biogas transport costs were estimated for the two grid types.

In this study we add to the scientific literature by applying the above mentioned transport model on a specific case study in Belgium. In this study we investigate the costs and benefits of a hub structure with a centralized CHP for agricultural digesters in the Province of West-Flanders. First, we perform a market study to identify the available digesters, their scale and location. Second, we investigate the potential scale advantages in heat and electricity production of using a centralized CHP. We analyse the costs of biogas transport, and see how much energy is used in the grid. As such we quantify the cost of additional electrical energy and heat production at a hub with a centralized CHP.

The remainder of this paper is structured as follows: In Section 2 the methodology is described. In Section 3 the case study is introduced, while results are provided in Section 4. In section 5 a discussion is added, and we end with the conclusions in Section 6.

2. Methodology

In this study two scenarios are evaluated: (1) **reference scenario** (scenario 1 ‘reference scenario’), and (2) **hub scenario** (scenario 2 ‘hub scenario’). The reference scenario consists of digesters each feeding an individual CHP at the digester site (Fig. 1). Assumed is that all electricity produced at a digester site can be effectively used, but heat has no value; this fits a situation with a changed treatment of digestate with no heat demand. In the hub scenario, the biogas is transported to a hub via a biogas transport grid, see Fig. 2. At the hub the biogas can be used in a CHP to produce both electricity and heat that is valorised. The effective use of heat is limited to 50% of the total available heat at the hub, similar to Ref. [23]. If the hub can be at one of the digester sites (*i.e.* scenario 2.1 ‘hub at digester site’) transport of biogas produced in the digester at that site is not needed, leading to relatively lower total transport costs. But it also implies that heat demanding activities should be developed at this hub to make use of an increased amount of available heat energy. Alternatively a site with high heat

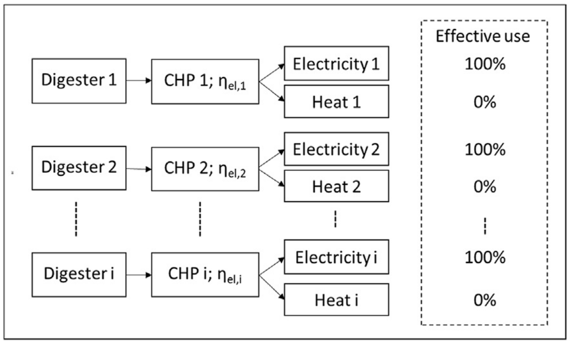

Fig. 1. Electricity production, reference scenario.

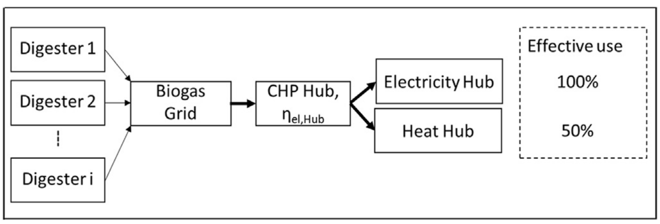

Fig. 2. Electricity production with use of a hub, hub scenario.

demand, that is not a digester site, could be established as a hub. Biogas transported by pipelines could be fed into a CHP at the hub and contribute to the heat demand (*i.e.* scenario 2.2 'hub at alternative location'). Moving the production of heat to a hub may leave the digester site with a heat shortage. Costs of heat replacement at the digester site is estimated based on a renewable heat cost of 0.02 € kWh_{th}^{-1} [23].

2.1. Biogas grid costs

The goal of the mathematical model we will use in this study is to find the grid with the lowest cost [18]. In the model the costs include investments, energy use for compression, operation, and maintenance for pipeline and compressor. Inputs, among others, are the capacity of the pipeline ($m^3\ h^{-1}$), the length (km) of the pipeline and operating time of 8000 h a^{-1}. Furthermore, five sizes of the pipeline diameter are available. As the goal of the model is to minimize the costs, the diameter is chosen appropriately. Biogas transport costs can be expressed in €ct m^{-3} or as annual biogas transport costs $C_{trans,year}$ in € a^{-1}.

2.2. CHP costs and efficiency, scale dependency

Both the electrical efficiency and specific investment cost of a CHP installation depend on scale [13,21,22,24]. In the reference scenario electricity costs are calculated taking into account CHP investment costs, O&M and costs of biogas production. The biogas production costs are 0.31 €m^{-3} based on Bekkering et al. (2012) [7]. The parameters for the cost calculation are presented in Appendix A.

ASUE e.V., a cooperative of 45 German gas companies, collected many data on electrical efficiency and costs of biogas CHPs in 2014 [24]. The data of 294 biogas CHPs are used to describe scale dependency with power functions in three ranges: 10 kW_e–100 kW_e, 100 kW_e–1 MW_e, and 1 MW_e–9 MW_e. The electrical efficiency, η_{el}, of a CHP lies between 28% and 46%, with larger CHPs having higher electrical efficiencies. The electrical efficiency of an installation can be calculated using the following equation:

$$\eta_{el} = a\,C^b \tag{1}$$

In Table 1 the values for the parameters a, C and b are provided. For CHP capacities lower than 10 kW_e, the same electrical efficiency is used as for 10–100 kW_e and for capacities higher than 9000 kW_e, the data for the category 1000–9000 kW_e is used. Results for electrical efficiency in Refs. [13,23] confirm the mathematical description of [24].

As the electrical efficiency of the CHP is scale dependent, in general the amount of electricity produced using the hub is larger than the amount produced by the individual CHPs at the digester sites. The additional electrical power as a result of this scale advantage ΔP_{el} is defined as:

$$\Delta P_{el}(\text{in } kW_e) = P_{el,hub} - \sum_{i\,\in\,grid} P_{el,i} \tag{2}$$

With $P_{el,hub}$ the electrical power (in kW) produced at the hub and $P_{el,i}$ the electrical power (in kW) produced at the individual digester site when no grid is implemented.

The amount of heat available at the hub is estimated using the electrical efficiency and the overall efficiency of the CHP of 85%. The assumption for the overall efficiency is in line with [23,24,26,27], although a higher total efficiency is possible especially if additional investments are made to recover heat from the exhaust gases [24].

The thermal power of the CHP at the hub, $P_{th,hub}$ in kW_{th}, is determined using the equation below. In the equation $\eta_{el,hub}$ is the electrical efficiency at the hub.

$$P_{th,hub}(\text{in } kW_{th}) = \frac{0.85 - \eta_{el,\,hub}}{\eta_{el,\,hub}} P_{el,hub} \tag{3}$$

Using the data from ASUE e. V [24] also the specific investment cost is determined and ranges from 400 to 3000 € kW_e^{-1}. Transport and installation costs amount to 45%–95% of the investment cost depending on the scale. The investment cost, C_m, can be determined using Equation (4). Table 2 and Table 3 provide the values for the parameters c, d, e and C.

$$C_m(\text{in } €kW_e^{-1}) = e \cdot c \cdot C^d \tag{4}$$

In Fig. 3 the specific investment costs as calculated with the ASUE scaling functions are compared with other references in a range up to 3000 kW_e. Van Dael et al. (2013) [23] suggest that the scale effect is limited to a maximum of 900 kW_e, specific costs above 900 kW_e are constant at 653 € kW_e^{-1}. Lanz et al. (2012) [13] use a power function for specific costs excluding installation costs; their paper presents data of biogas CHPs with a scale up to 600 kW_e. The ASUE brochure from 2012 seems to have underestimated the investment costs as compared to the 2014 version. In the last edition more attention is given to transport of the CHP and installation costs.

Replacing several CHPs for one larger CHP at a hub results in a CHP scale advantage; the difference in investment costs, ΔC_m (in €), is found using the following equation:

Table 1
Parameter values to calculate the electrical efficiency of a CHP based on [24].

Power C [kW_e]	a	b
$10 \le C < 100$	0.21636	0.1149
$100 \le C < 1000$	0.29667	0.0503
$1000 \le C < 9000$	0.31577	0.0385

$$\Delta C_m(\text{in } €) = C_{m,hub} - \sum_{i \in grid} C_{m,i} \quad (5)$$

With $C_{m,\,hub}$ the investment cost of the CHP at the hub and $C_{m,\,i}$ the investment cost for the individual CHP at the digester site. Note that ΔC_m is negative. The difference in investment cost is converted to a negative annual cost, $\Delta C_{m,year}$, with yearly O&M costs calculated as 5% of investment costs [18] and reduces the costs attributed to the electricity and heat production at the hub.

2.3. Costs attributed to the additional electricity and heat production

In the simulation the choice of digesters to be added to the biogas grid is based on annual costs per kW_e of additional power, $C_{\Delta P}$. These costs include the annual biogas transport costs in the grid, $C_{trans,year}$ (Section 2.1) and the annual CHP scale advantage, $\Delta C_{m,year}$ (Section 2.2), and are calculated as described in Equation (6).

$$C_{\Delta P}(\text{in } € kW^{-1} a^{-1}) = \frac{C_{trans,year} + \Delta C_{m,year}}{\Delta P_{el}} \quad (6)$$

If the hub is at a digester site, the other digesters are added one by one to the grid selected by minimum $C_{\Delta P}$. If the hub is at a non-digester site, the combination of 2 digesters with lowest $C_{\Delta P}$ is determined as a starting point of the simulation and then digesters are added using the same criteria. Note that the calculation of costs per unit of additional electrical energy kWh_e can be determined by dividing $C_{\Delta P}$ by 8000, *i.e.* the operating time.

The costs that are linked to the implementation of a biogas transport grid are allocated to the additional electricity and heat production by the CHP at the hub. These include the biogas transport grid and the negative CHP scale advantage costs. We assume 80% of the costs to be attributed to production of additional electrical energy, and 20% of the costs to heat production [23].

3. Case study

In the Flemish Province of West-Flanders (Belgium), 38 digesters can be identified, status 2015 [28]. The biogas from these digesters is used to produce heat and electricity at or close to the digester site. As explained in the introduction the need of heat at agricultural digester sites may strongly reduce as a result of a change in digestate treatment. The data on the 38 digesters (Fig. 4) includes locations, addresses of the digester sites, digester scales in kW_e, and biomass sources. The addresses are transformed into World-Geodetic-System-84-coordinates (WGS84) using Google-maps, information from environmental permits and land registry (Cadgis [29]). From these coordinates Universal Transfer Mercator (UTM) coordinates are calculated in MatLab, to allow calculations of distances from digesters to a hub in a Cartesian plane. More than half of the digesters are “mainly agricultural”, while for 25% of the produced power the biomass source is not specified. Variation in scale of digesters for different biomass sources is large in digesters which are labelled “mainly agricultural”, however, the majority of these digesters are rather small. The basic data are available in Appendix B.

The digester scale Q_S, measured in $m^3\,h^{-1}$ biogas produced, is estimated using the digester power P_{el} in kW_e and the electrical efficiency following Equation (7).

$$Q_S(\text{in } m^3 h^{-1}) = \frac{P_{el}}{\eta_{el}} \cdot \frac{3.6}{0.538 \cdot 35.8} \quad (7)$$

Where the methane lower heating value (LHV) is 35.8 MJ m^{-3}, the methane volume of the biogas is assumed to be 53.8% [18], and the electrical efficiency η_{el} is based on the formulas presented in Table 1.

Table 2
Parameter values to calculate the investment cost of a CHP based on [24].

Power C [kW_e]	c	d
$10 \le C < 100$	9881.2	−0.500
$100 \le C < 1000$	4276	−0.325
$1000 \le C < 9000$	1000.1	−0.117

Table 3
Parameter values to incorporate Transport and Installation costs, adapted from Ref. [24].

Power C (kW_e)	e
$C < 3$[a]	1.59
$3 \le C < 10$[a]	1.51
$10 \le C < 100$	1.45
$100 \le C < 350$	1.51
$350 \le C < 500$	1.60
$500 \le C < 750$	1.66
$750 \le C < 1000$	1.74
$1000 \le C < 1500$	1.95
$1500 \le C < 5000$	1.77
$5000 \le C < 9000$	1.62

[a] No value of c and d available, so we use c = 9881 and d = −0.500 similar to the regression formula in the range $10 \le C < 100$.

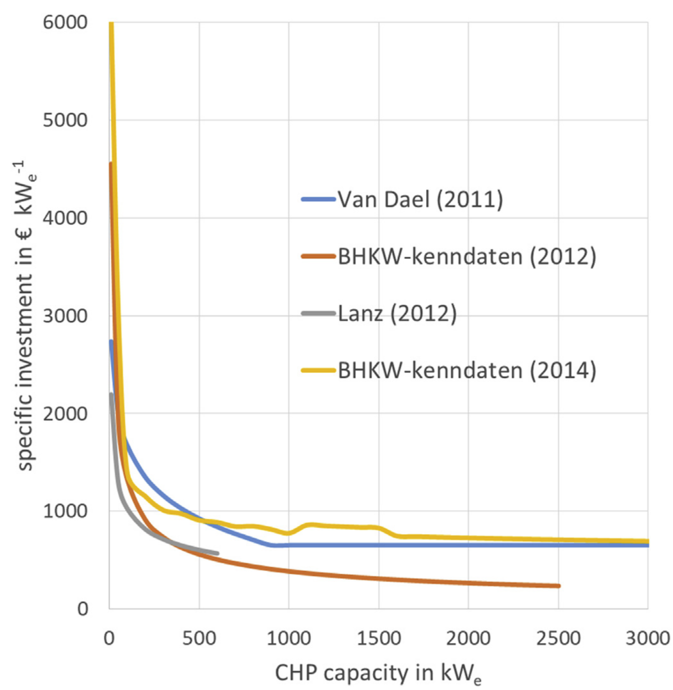

Fig. 3. Biogas CHP, specific investment costs for references Van Dael [23], ASUE 2012 [25], Lantz 2012 [13] and ASUE, BHKW kenndaten 2014 [24].

4. Results and discussion

4.1. Scenario 1 - reference scenario

The costs of electricity production at the individual agricultural sites for the reference scenario are presented in Fig. 5 with every data point representing one site. The scale dependency of the CHP electrical efficiency causes a scale dependency in biogas contribution. However, in all cases the larger part of the costs is due to the biogas cost, ranging from 65% for a CHP with installed power smaller than 10 kW_e to 90% for a larger CHP with installed power of more than 1500 kW_e. Leaving out small digesters with a scale smaller than 20 $m^3\ h^{-1}$ biogas, gives a typical range of 14–18 €ct kWh_e^{-1}. Note that it is assumed that all costs are attributed to electricity production in this scenario, simulating a situation where heat has no economic value.

4.2. Scenario 2 - hub scenario

4.2.1. Scenario 2.1 - hub at digester site

The transport costs for a pipeline of 10 km at a small scale of 8 $m^3\ h^{-1}$ biogas could be 1.75 € m^{-3} biogas, which is relatively high. Therefore small digesters are left out, and the initial set of digesters in the case study is reduced to all agricultural digesters with a production of >20 $m^3\ h^{-1}$, *i.e.* 12 digesters. These digesters, with an example of a star layout grid, are shown in a map in Fig. 6. In the figure, the numbered labels identify each digester as in Appendix B. The minimum distance between two digesters is 2.34 km (labels 20 and 27), while the maximum distance is 41.24 km (labels 5 and 9). The average distance to the other digesters for the digester labelled 35 is 17.32 km, with a standard deviation of 4.88 km. While for the exocentric digester labelled 31, these values are 31.48 km and 9.34 km respectively.

In this first scenario it is assumed that the hub is at a digester site, meaning that biogas transport costs for one of the digesters is avoided. In this study we have chosen to present simulations with the following digester sites to be the hub: 18, 20, 26, 27, and 35. The choice for digester 18 is made because it has the largest scale within the set of 12 digesters. Digesters 20 and 27 are chosen because these are two digesters close to each other. Finally digesters 26 and 35 are chosen because they are respectively positioned exocentric and at the centre of the region.

The total potential electrical and heat power produced at the hub is calculated using scale dependency as described in Section 2. Depending on the number of digesters linked to the hub, the electrical potential varies between 0 and 30,000 kW_e. The heat potential varies between 0 and almost 25,000 kW_{th}.

4.2.1.1. Biogas transport costs.

Fig. 7 shows that when the hub is situated at a large digester (*i.e.* site 18), the biogas transport costs to the hub are lowest because no transport of this large biogas volume takes place. However, when the biogas scale at the hub becomes larger than 8000 $m^3\ h^{-1}$, the transport costs seem not to differ from other hubs, except for a hub at digester site 26. The latter site is situated exocentric and shows clearly higher biogas transport costs, as expected. The biogas transport costs for biogas produced by the smaller digesters are high and we see in our simulations that the digesters labelled 9 and 29 are therefore added last.

4.2.1.2. Scale advantage - electrical efficiency.

To have an indication of the scale advantage in electrical efficiency, the electrical power of the CHP at the hub is compared with the sum of the electrical power of the individual CHPs that are added to the grid. In Fig. 8 the lower lines show the sum of the electrical power of the individual CHPs that are added in the simulation to the grid, depending on the hub site. The upper line, labelled 'hub', shows the electrical power of one large CHP at the hub. By using the biogas in the more

Fig. 4. The 38 digesters in the Province of West-Flanders (Google maps).

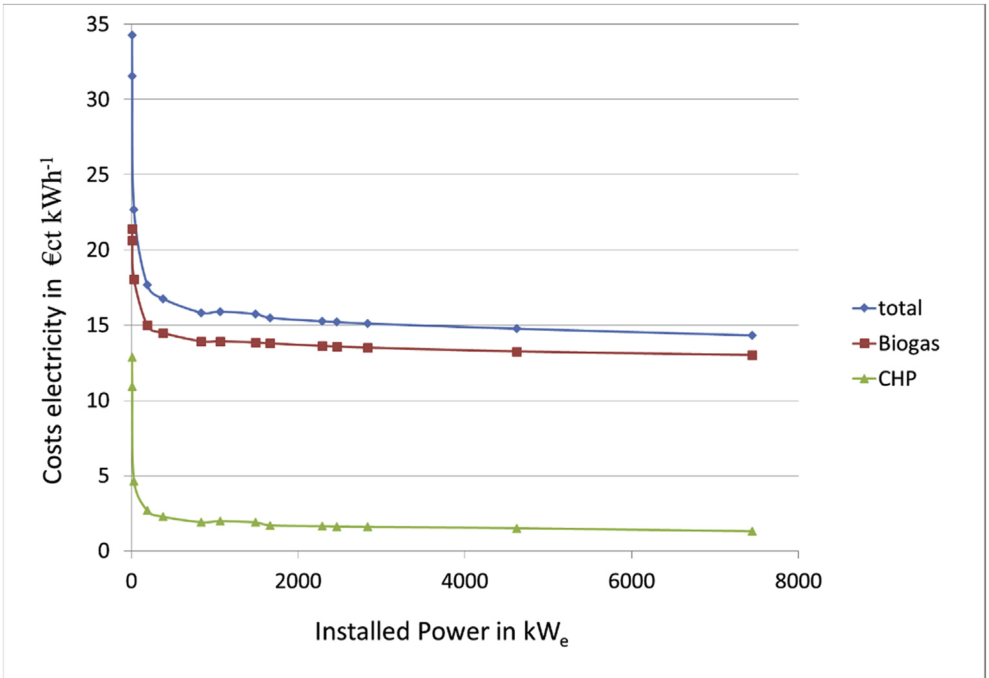

Fig. 5. Electricity production cost of individual CHP depending on size.

efficient CHP at the hub, more electricity can be produced. The additional electrical power can be up to 2.4 MW_e if all biogas is collected at the hub, an increase of 9%. If all the biogas is transported to the hub, the total biogas at the hub is close to 12,000 $m^3\ h^{-1}$.

Fig. 9 shows the difference in additional electrical power depending on the hub site. In the figure a difference in additional power can be seen up to a hub scale of ca. 8000 $m^3\ h^{-1}$. For larger scales, the lines in the figure converge showing that when all digesters are added, the additional electrical energy is the same, independent of the hub site.

When the hub is at digester site 27, using the decision criteria of lowest costs per additional kWh_e, implies that relatively small digesters are added first in the simulation. As such the gain in electrical efficiency is large and this results in a relatively high additional electrical power for smaller biogas scales. Whereas when the hub is at site 18 the large digester at that site already produces at a high efficiency and adding the biogas of a second digester does not greatly affect the electrical efficiency of the large CHP, resulting in only a small amount of additional electrical power. Adding a large digester to a hub at one of the other sites has a similar effect, and the slope of line segments for these are therefore relatively small.

4.2.1.3. Scale advantage – investment cost CHP. The scale difference between the CHP at the hub and the scales at the individual digester sites gives rise to a financial scale advantage presented as negative annual costs in Fig. 10. Again the lines converge. However, a hub at sites 18 or 35 remain above the others up to ca. 8000 $m^3\ h^{-1}$, indicating that a scale advantage in specific investment costs with several smaller CHPs is more pronounced. For small hubs with a limited number of digesters, the scale advantage can be up to 70% of the transport costs, but for most cases it shows to be around 20%, thereby the relevance of modelling CHP costs scaling is established.

4.2.1.4. Allocation of costs. Combining the above described results allows us to calculate the total costs associated with the biogas grid and combined with the assumptions described in the Methodology section, the costs for additional electricity and heat are calculated.

The costs allocated to the additional electricity are provided in Fig. 11. In the reference scenario the costs for decentralized production of electrical energy at the digester sites leads to production

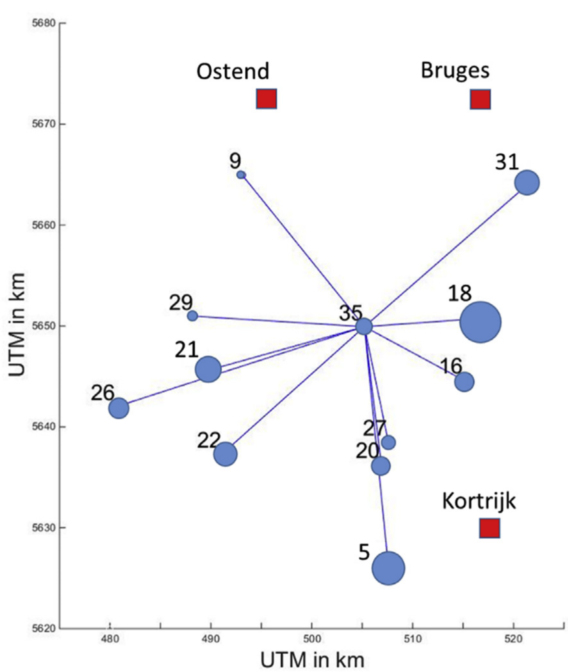

Fig. 6. Example of a potential star layout grid. The digester scale is represented by the area of the circle. Labels refer to labels in Appendix B. For orientation the position of some cities is shown. UTM = Universal Transfer Mercator.

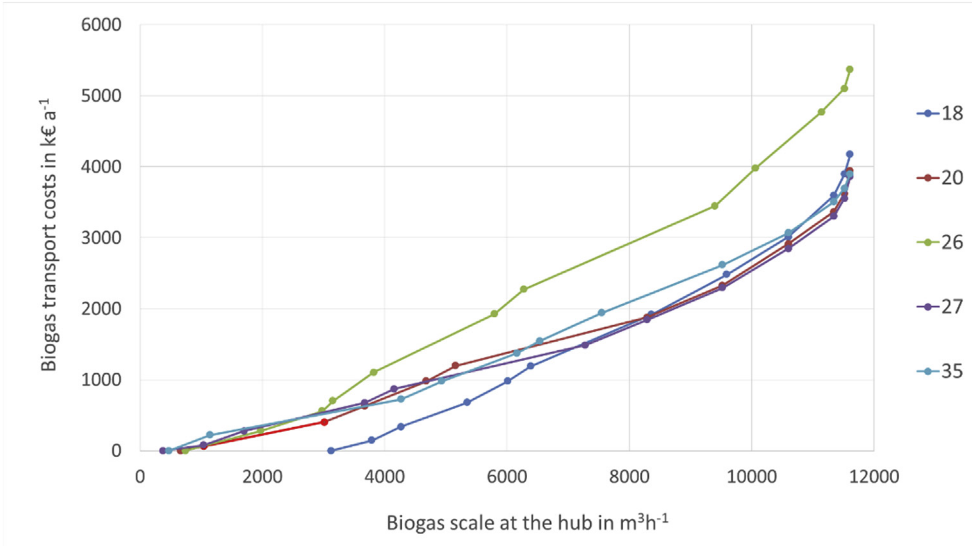

Fig. 7. Biogas transport costs with the hub at the indicated digester site.

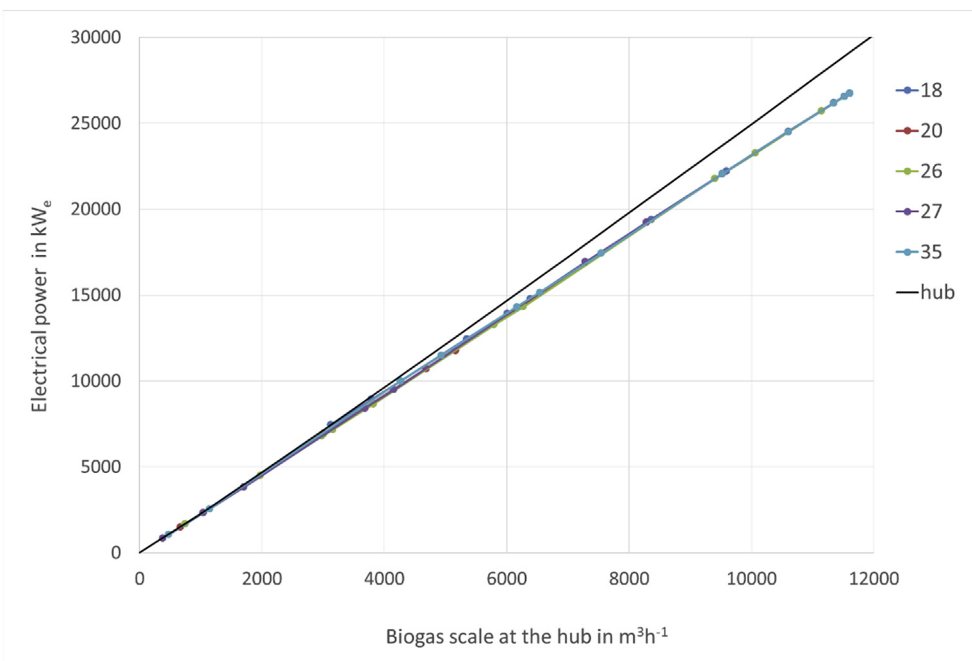

Fig. 8. Comparing the sum of electrical power of individual CHPs with the CHP at the hub.

costs around 16 €ct kWh_e^{-1} (Fig. 5). A small digester matched up with a large digester (site 18) results in low costs for the additional electrical energy. The hub at site 35 has a relatively small digester and it appears to be wise to add more than one digester to reduce the costs per unit of additional electrical energy. The relatively small scale digesters at sites 20 and 27 are close together with a distance of 2.3 km. Combining the biogas at site 20 results in low costs, 4.0 €ct kWh_e^{-1} (Table 4). We also find that the average cost per kWh_e produced at the hub is lower compared to individual digesters and that 2% more electricity is produced. Note that costs of the additional electricity do not depend on the costs of biogas, but costs of electricity at the individual digester sites do (Section 4.1). Combining biogas from site 20 with site 27 results in an acceptable electricity cost of 7.6 €ct kWh_e^{-1}. For most hubs the costs for additional electrical energy are around 11 €ct kWh_e^{-1} when biogas is collected from many digesters, *i.e.* the scale at the hub is over 8000 m^3h^{-1}. For the exocentric digester at site 26 the costs of additional electrical energy are relatively high, ranging from 15 to 20 €ct kWh_e^{-1}. The model shows that implementation of a hub can increase the electricity production at competing costs. Appendix C discusses details of some other examples.

Fig. 12 shows that the heat costs are within a wide range, *i.e.* 0.05 to 1 €ct kWh_{th}^{-1}, depending on the specific set of digesters in the grid. In general, the maximal heat availability at a hub is less than

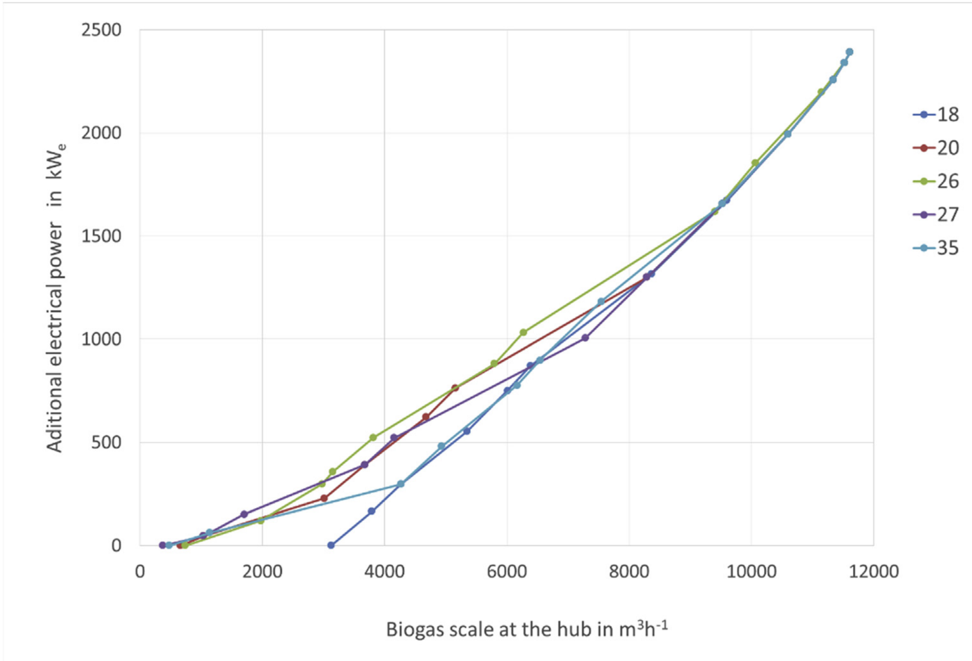

Fig. 9. Additional electrical power depending on biogas scale.

the sum of the maximal heat at the individual digester sites due to a decreasing heat efficiency with increasing scale of CHP. Taking 2 €ct kWh_{th}^{-1} [23] as a benchmark, the model predicts that heat production is economically feasible. However, using a CHP at a hub leaves the digester sites without heat production; so if some heat is still needed, this should be supplied from a non-biogas source. Costs for the replacement of heat needed at the digester sites adds to heat costs at the hub, but are not included yet. If replacement at the digester sites requires as much as 10% of the total heat at the hub, and the costs of this replacement heat is set at 2 €ct kWh_{th}^{-1}, then 0.4 €ct kWh_{th}^{-1} should be added to the values in the graph of Fig. 12, as the effective heat use is 50%. This does not change the conclusion about the economic feasibility. So in case digestate processing is changed to a process not requiring large heat input, heat replacement costs can be relatively low. To make optimal use of the CHP at a hub, one could either look for a heat sink *e.g.* district heating, industry or greenhouses, or develop heat dependent business at the hub site. This is proven for a natural gas CHP [17], and is similar for biogas. Furthermore, subsidy regimes can support the more efficient use of renewable heat [10,23].

Note that alternative cost allocation percentages between electricity and heat require only proportional adjustment. For example if 40% of costs are attributed to the additional electrical energy, the vertical scale in Fig. 11 ranges from 0 to 15 €ct kWh_e^{-1} instead of

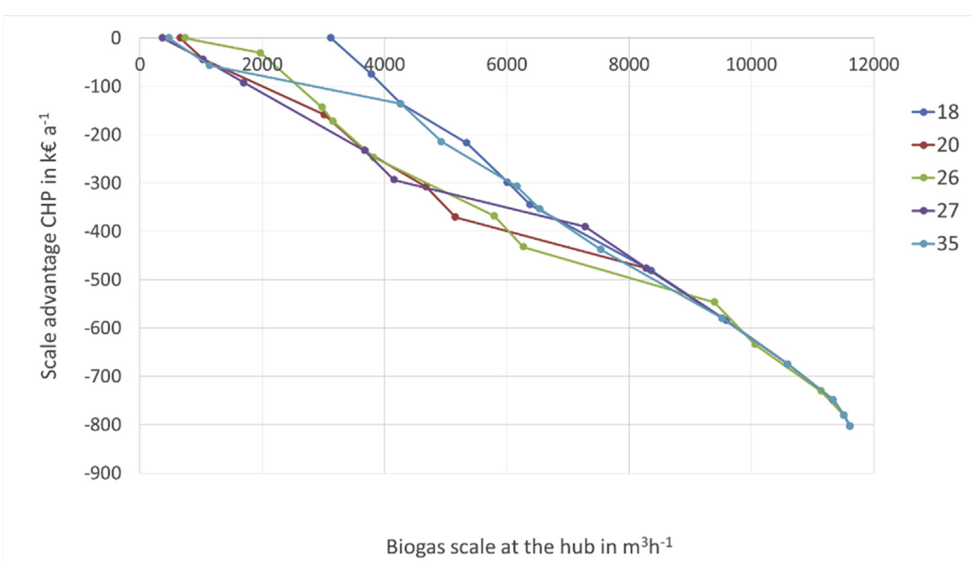

Fig. 10. Economic scale advantage with the hub at the indicated digester site.

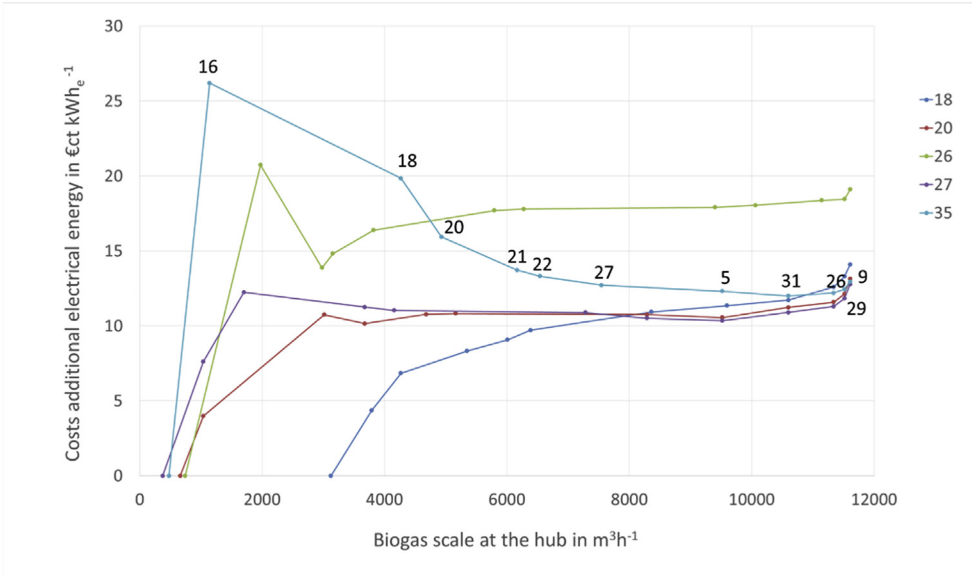

Fig. 11. Costs of the additional electrical energy. For the hub at site 35 the labels on the graph indicate the order in which digesters are added to the grid.

0–30 €ct kWh$_e^{-1}$.

In the results allocation of costs is on an 80% to 20% basis for additional electricity and heat respectively; other ways of attribution could be used, *e.g.* in order to match local value of either of the commodities other percentages could be used. In appendix D alternative ways of cost attribution are elucidated.

4.2.1.5. Electrical power for biogas transport. The biogas transport consumes electrical energy for compression (Fig. 13). In all but one simulation the additional power at the hub is larger than the compression power in the grid. Only when the hub is at site 9, not shown in the graph, is the electrical energy needed for compression larger than the additional electrical energy produced. Site 9 is exocentric and its digester is relatively small, resulting in relatively high compression power need and low electrical scale advantage. We would like to note that the source of electrical compression power does not need to be biogas, but could also be *e.g.* partly solar or wind energy. In that case, additional electrical energy from biogas is produced. Biogas has the advantage that it is relatively easy to store, so energy system flexibility can improve.

4.2.2. Scenario 2.2 - hub at an alternative location

In Roeselare and Ostend heat grids were developed and expansion is planned [30]. Biogas produced in the selected agricultural digesters could serve as a source of heat using a grid with a hub at these locations. In Appendix E details of two locations used in this study are given and the grid, a star lay out, is shown. The hub is assumed to be at one of the (planned) heat sources in the heat grid. Roeselare is located at the centre of the region, while Ostend is exocentric, at the coast.

4.2.2.1. Costs of additional electricity and heat. The model is used to calculate the biogas transport costs from the digesters to the hub. If the grid contains only one digester, no CHP scale advantages are involved. In that case all biogas transport costs are attributed to the heat production. The lowest biogas transport cost per m^3 are from the large digester 18 to the hub. Heat costs at the hub are 1.95 €ct kWh$_{th}^{-1}$ and 3.66 €ct kWh$_{th}^{-1}$ (Table 5) for Roeselare and Ostend respectively. Taking into account the benchmark of 2 €ct kWh$_{th}^{-1}$ the costs for Ostend are not competitive.

Fig. 14 and Fig. 15 present the costs of additional electrical energy and heat at the hub when more than one digester is in the grid. Again it shows that costs for Ostend are high; on the other hand costs for additional electricity in Roeselare are under 20 €ct kWh$_e^{-1}$, when more than 2 digesters are in the grid. For heat production similar observations can be made, for Roeselare heat costs seem to be acceptable. In both cases the large digester 18 is selected at the start of the simulation. For Roeselare digester 18 combines first with digester 5, although biogas transport costs are lower for digester 20. Combining digesters 18 and 5 induces a relatively large increase in additional electrical energy as compared to combining digesters 18 and 20. Although digester site 9 is relatively close to Ostend, the small scale causes high biogas transport costs; it is therefore not a favourite for participating in the grid.

Fig. 16 allows the variation of attribution percentages; it shows that for a grid with 3 digesters (18, 5 and 20) 521 kW$_e$ additional electricity and 1179 kW$_{th}$ heat is produced at the hub. The results for the 80%–20% is indicated, costs of 19.61 €ct kWh$_e^{-1}$ and 0.42 €ct kWh$_{th}^{-1}$. If 15 €ct kWh$_e^{-1}$ are attributed to additional electricity, heat costs are around 0.8 €ct kWh$_{th}^{-1}$. If heat costs are set to 1.5 €ct kWh$_{th}^{-1}$, costs of additional electricity are around 8 €ct kWh$_e^{-1}$; as a comparison the average costs of the individual CHPs in this grid is 14.81 €ct kWh$_e^{-1}$. These values suggest a feasible business case. A large CHP at the hub produces 3.8% more electrical energy as compared to individual CHPs at the digester sites.

4.2.2.2. Costs of traject specific pipelines. In the calculations pipeline costs include 60% of the pipeline to be easily installed (*e.g.* in farmland) and 40% to take more effort *i.e.* difficult (*e.g.* passing

Table 4
Power and (average) electricity costs with hub at site 20.

		Power [kW$_e$]	Costs [€ct kWh$_e^{-1}$]
Individual CHPs	Digester 20	1486	15.75
	Digester 27	835	15.84
	Total	2321	15.78
Hub	Total hub	2368	15.55
Additional power hub	kW$_e$	47	3.99
	%	2%	

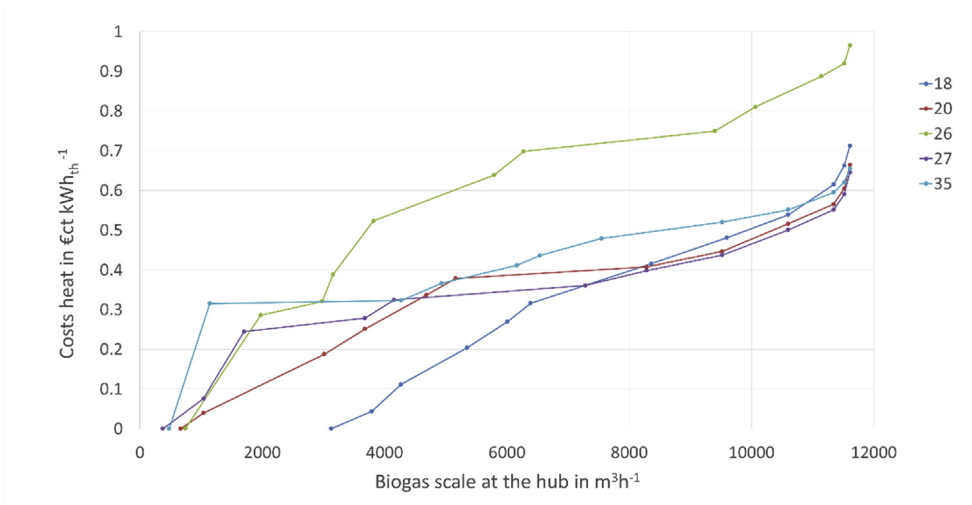

Fig. 12. Heat costs at the hub.

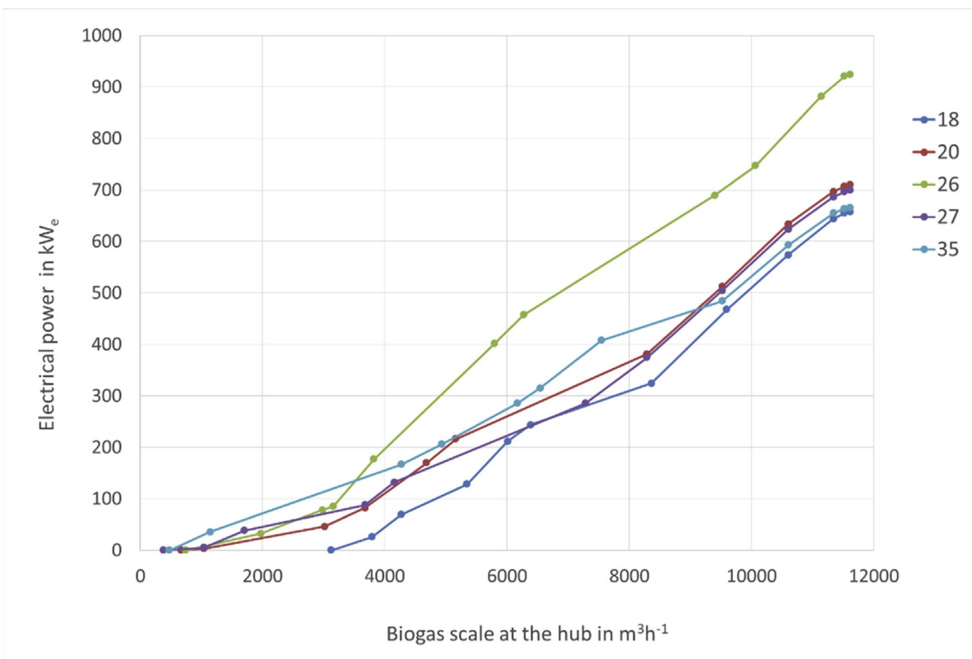

Fig. 13. Compression power in the biogas transport grid.

roads), see appendix A. For the hub at Roeselare, Fig. E1 in Appendix E, an assessment of the grid on a map showed that part of the pipeline passes through the built environment of cities. In Table 6 an estimation of the length of pipelines in the cities is shown. In a sensitivity analysis costs of this section of the pipeline were taken to be entirely ‘difficult’ while the remaining pipeline sections were taken to be 60% ‘easy’ and 40% ‘difficult’. As a result the biogas transport costs in some pipelines measured in €ct m^{-3} increased by 4–11%, while costs for additional electrical energy increased, in €ct kWh$_e^{-1}$, with 3% for a grid with 9 or more digesters, to 6% for a grid with 4 or less digesters. The preferred order in which the digesters were added to the grid in the simulation did not change.

Table 5
Heat costs and production, one digester in the grid.

Hub at	Digester label	Biogas scale [m^3 h^{-1}]	Heat production, assumed 50% effective	Heat costs [€ct kWh$_{th}^{-1}$]
Roeselare	18	3127	3.4 MW	1.95
Ostend	18	3127	3.4 MW	3.66

4.2.2.3. Electrical power for biogas transport. Biogas transport consumes electrical energy for compression (Fig. 17). The longer distances from the digesters to Ostend cause higher consumption of compression electrical power as compared to Roeselare. For

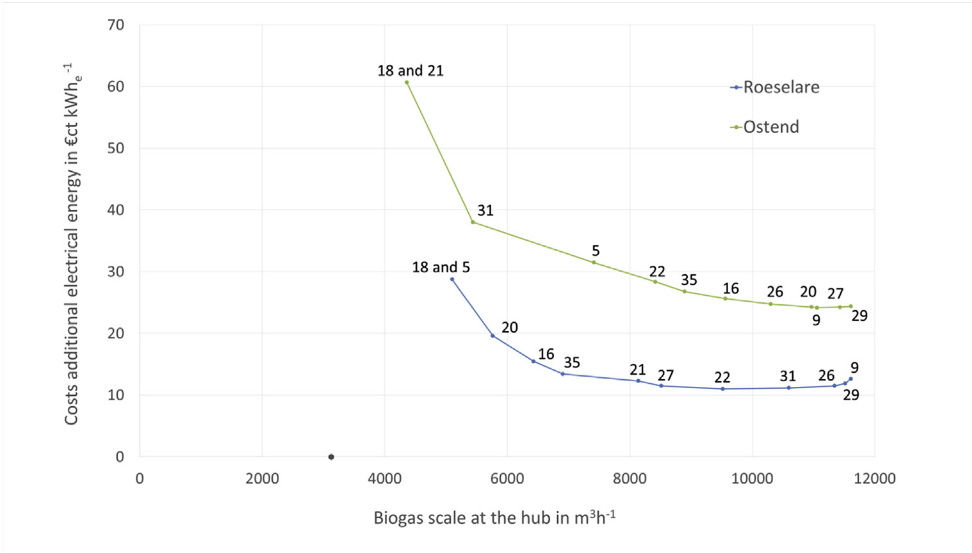

Fig. 14. Costs of the additional electrical energy. The labels indicate the order in which digesters are added to the grid.

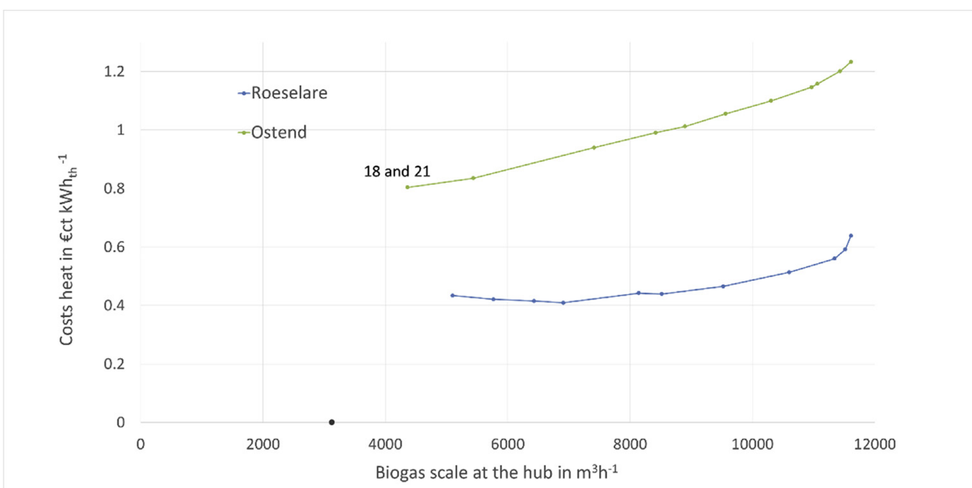

Fig. 15. Costs of heat.

Roeselare, with one digester in the grid, 136 kW_e electrical power is used to produce 3.4 MW_{th} heat at the hub, *i.e.* 169 $W_{th}\ W_e^{-1}$. For two or more digesters in a grid with a hub at Roeselare the additional electrical power is higher than the compression power needed in the grid. For Ostend this is only the case for 3 or more digesters in the grid.

5. Discussion

In the case of a natural gas CHP large scale installations usually do not support flexible energy production as well as small scale installations; *e.g.* start-stop procedures are more complicated, efficiencies are lower if deviated from nominal power and maintenance costs increase with flexible use. Still, in general, flexible CHPs are more profitable than "must run" installations as they can adapt to variation in electricity price. In a scenario with high implementation of renewable energy, flexible CHP proves to be important to fill in periods of low renewable energy production [31]. A study of natural gas CHPs shows that even for large scale CHPs flexible "electricity driven" installations are preferred [16]; optimization of sizing and operational strategy can increase efficiency and reduce costs [17]. This information most likely is valid for a biogas CHP too. In this case study a steady state is assumed and flexibility is not taken into account.

An alternative route to avoid waste of heat from a CHP at a digester site is to upgrade the biogas to biomethane, *i.e.* to natural gas quality. This biomethane can be injected in the natural gas distribution grid. In this way the biomethane can be used at many appropriate sites at a preferred moment. Research efforts aim to develop affordable small scale upgrading and injection facilities

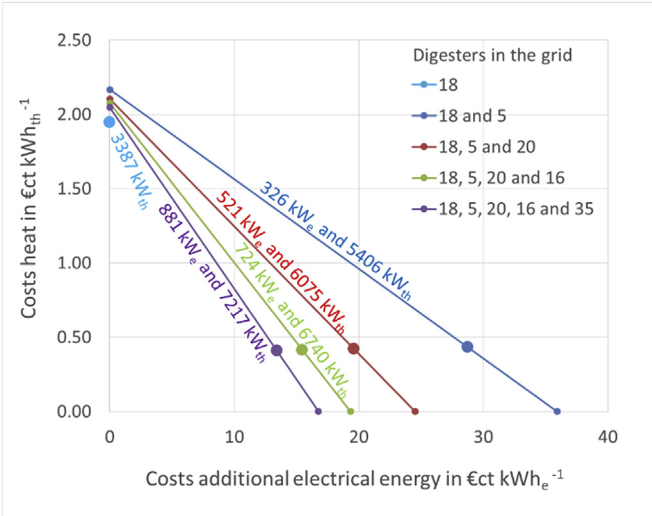

Fig. 16. Relation between costs of additional electricity and costs of heat with hub at Roeselare; first five grids are shown.

Table 6
Estimated part of pipeline passing cities for a pipeline from the indicated digester to the hub at Roeselare.

Digester label	Percentage
5	15%
16	40%
18	30%
31	15%
35	15%

[32]. Biogas collected at a hub can also be used to be upgraded to natural gas quality. A model replacing decentralized biogas upgrading by a dedicated biogas pipeline infrastructure with upgrading at a larger scale at a hub shows a financial advantage [33]. In this case study the use of a centralized CHP at a digester site showed lower energy costs than using an alternative location, provided a heat sink is available in the proximity of that digester site.

An initiative of gas infrastructure companies looks into reuse of part of existing natural gas infrastructure as a biogas grid to collect biogas for centralized upgrading and injection in the natural gas grid [34]. The idea of building a "virtual pipeline" with compressed biogas in cylinders transported by trucks is researched in several research groups and companies [35–37].

The grid in this case study is a "Star layout", wherein individual biogas producers use their own pipelines. Costs are reduced when biogas from several digesters is collected in a main pipeline that leads to hub, using a "fishbone layout". From Fig. 6 it can be suggested that *e.g.* the pipelines from sites 5, 20 and 27 to a hub at site 35 could be combined. Using modelling results for a region [18] a cost reduction of 10–40% is estimated.

As can be concluded, from an economic point of view, a biogas grid can be an economically viable option. For implementation of such a grid many different stakeholders will be involved in setting up and exploiting the biogas grid. First, the participants in the biogas production value chain will be involved: biomass supplier, biogas producer and digestate processor. For the biogas transport, biogas grid owner and operator will be involved. At the hub, the CHP owner is another actor. And finally, when selling the electricity and heat, the electricity grid owner or electricity buyer, as well as the heat user will be important to make sure that the implementation is successful. To conclude the resulting business model will be complex which involves, among others, ensuring profitability of each stakeholder, distribution of roles and responsibilities, legal aspects and securities.

6. Conclusions

In the case study "West Flanders" costs of electricity and heat are estimated for a dedicated regional biogas grid connecting 12 agricultural digesters with centralized electricity and heat production. Heat may not be used effectively at the digester sites.

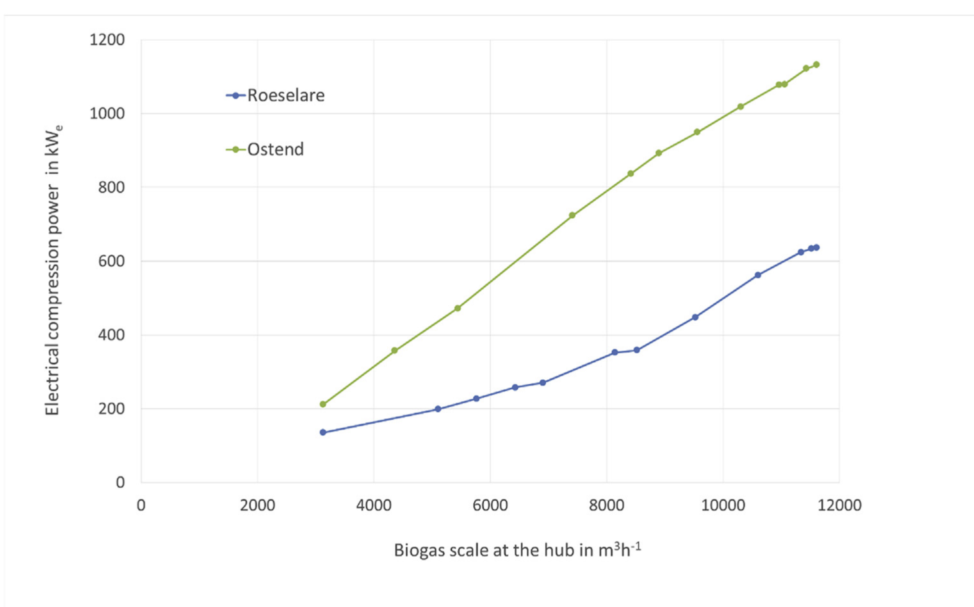

Fig. 17. Compression power in the biogas transport grid.

Therefore collecting biogas at a hub with a heat sink could improve the overall energy efficiency of biomass use.

Costs of electricity and heat are modelled based on yearly biogas transport costs. A large scale centralized CHP at a hub is compared to decentralized CHPs at the digester sites. The collection of biogas from digesters to a hub with pipelines induces a scale advantage in electrical efficiency. In the case study the highest increase in electricity production is 2.4 MW_e or 9% when all biogas is collected at the hub.

If costs of electricity from biogas at the digester sites are used as a benchmark, the costs of additional electricity at a hub located at a digester site is often in the same order of magnitude or lower. The costs of heat at such a hub are shown to be lower than the benchmark of 2 €ct kWh_{th}^{-1} assuming an effective heat use of 50%. If a hub is not at a digester site, but at a central location with high potential heat demand, transport of biogas from one digester to the hub leads to 3.4 MW heat production with costs in the same order of magnitude as the benchmark. Such a hub collecting biogas from two digesters in a grid, induces high costs of additional electricity. However these are lower than 20 €ct kWh_e^{-1} for grids with more than two digesters. Heat costs are lower than the benchmark. Moreover, using different attribution percentages, costs of additional electrical energy and heat are shown to be competing. Overall it can be concluded that the scale advantage of a centralized CHP can be a driver to collect biogas at a hub using a biogas grid.

Further research could aim for an improvement of the biogas grid model making the costs of pipelines even more site specific or extending the model by introducing flexible electricity or heat production. Storage of biogas, including a contribution of line-pack storage in the biogas grid can support such flexibility. An alternative is the upgrading of biogas and injection of biomethane in the natural gas grid; a case study could be performed to analyse scenarios with and without a dedicated biogas grid. For such a system, business models have to be developed, and legal aspects need to be considered, including subsidy regulations.

Author contribution

E.J. Hengeveld: Conceptualization; Methodology, Software, Writing - Original Draft. J. Bekkering: Conceptualization; Writing - Review & Editing. M. Van Dael: Conceptualization; Writing - Review & Editing. W.J.T. van Gemert: Conceptualization; Writing - Review & Editing. A.A. Broekhuis: Conceptualization; Writing - Review & Editing; Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2019.12.009.

Appendix A

Table A1 shows parameters for the Net Present Value calculations.

Table A1
Input data NPV calculation.

Parameter	Value
Electricity costs [€ kWh^{-1}]	0.14
Inflation [%]	2
Equity share in investment [%]	20
Debt share in investment [%]	80
Required return on equity [%]	7
Interest on debt [%]	7
Corporate income tax rate [%]	25.5
Depreciation period non pipelines [a]	12
Depreciation period, pipelines [a]	30
Yearly O&M, % of investment, non pipelines [%]	5
Yearly O&M, % of investment, pipelines [%]	2

Pipeline costs, as shown in Table A2, include the costs to install the pipeline. It is assumed that 60% of the pipeline can be easily installed (*e.g.* in a farmland) and 40% takes more effort, *i.e.* difficult (*e.g.* passing roads), except in section 4.2.2.3. Operation and maintenance can be taken to be 2% of the investment each year. For the pipelines a longer depreciation period is acceptable; in the model the depreciation period for the pipelines is set at 30 years as in Ref. [18].

Table A2
Pipeline diameters and costs HDPE pipelines

Outside diameter [mm]	Inside diameter [mm]	€ m^{-1} easy	€ m^{-1} moderate	€ m^{-1} difficult
110	90.0	40	100	160
160	130.8	80	120	170
200	163.6	98	134	210
250	204.6	123	198	258
315	257.8	135	215	300

Appendix B

Table B1
Data digesters in the Flemish Region of West-Flanders

ID digester	Address	Date in use	Date subsidy (GSC/GVO)	Grid operator
1	Kiviethoek 1, 8647 Lo-Reninge	21/10/2015	21/10/2015	Gaselwest
2	Rollegemkapelsestraat 76, 8880 Sint-Eloois-Winkel	08/09/2014	08/09/2014	Infrax West
3	Maria-Aaltersteenweg 36, 8730 Beernem	20/06/2014	20/06/2014	Imewo
4	Vlamingstraat 28, 8560 Wevelgem	24/01/2014	24/01/2014	Infrax West
5	Ropswalle 26, 8930 Menen	05/12/2013	14/11/2013	Gaselwest
6	Bargiestraat 6, 8900 Ieper	22/07/2013	12/12/2003	Gaselwest
7	Sint-Pietersbruglaan 1, 8552 Moen	19/07/2013	19/07/2013	Gaselwest
8	Vullaertstraat 92, 8730 Beernem	04/07/2013	04/07/2013	Imewo
9	Bazelaar 1, 8470 Gistel	06/05/2013	28/03/2013	Infrax West
10	Houtemstraat 33, 8980 Zonnebeke	15/04/2013	15/04/2013	Gaselwest
11	Vossenholstraat 18, 8755 Ruiselede	27/03/2013	27/03/2013	Gaselwest
12	Gistelsteenweg 577, 8490 Jabbeke	14/12/2012	14/12/2012	Infrax West
13	Pervijzestraat 69, 8600 Diksmuide	27/07/2012	27/07/2012	Infrax West
14	Zwart-Paardstraat 2, 8630 Veurne	27/07/2012	27/07/2012	Gaselwest
15	Zevekotestraat 107, 8470 Zevekote	27/07/2012	27/07/2012	Infrax West
16	Wezestraat 61, 8850 Ardooie	12/04/2012	14/04/2012	Gaselwest
17	Molendreef 22, 8972 Proven	28/03/2012	28/03/2012	Gaselwest
18	Brugsesteenweg 176, 8740 Pittem	21/11/2011	14/12/2011	Gaselwest
19	Albert I laan 33, 8630 Veurne	07/10/2011	19/04/2012	Gaselwest
20	Breulstraat 122 A, 8890 Moorslede	03/01/2011	07/01/2011	Gaselwest
21	Heulegoedstraat 9, 8650 Houthulst	06/01/2010	06/01/2010	Gaselwest
22	Bargiestraat 4, 8900 Ieper	01/01/2010	04/12/2012	Gaselwest
23	Vijfstraat 8, 8740 Pittem	06/07/2009	23/06/2010	Gaselwest
24	Moorseelsesteenweg 32, 8800 Roeselare	07/05/2009	07/05/2009	Gaselwest
25	Regenbeekstraat 7 c, 8800 Roeselare	18/02/2009	18/02/2009	Gaselwest
26	Westvleterenstraat 25 a, 8640 Vleteren	23/10/2008	23/10/2008	Gaselwest
27	Galgestraat 16, 8800 Rumbeke	07/08/2008	07/08/2008	Gaselwest
28	Waterstraat 40, 8530 Harelbeke	05/11/2007	29/12/2007	Infrax West
29	Jagersstraat 4 A, 8600 Diksmuide	15/09/2007	10/06/2011	Infrax West
30	Kortrijksesteenweg 266, 8530 Harelbeke	15/03/2007	01/04/2007	Infrax West
31	Wellingstraat 107 A, 8730 Beernem	01/03/2007	14/05/2007	Imewo
32	Bargiestraat 1, 8900 Ieper	05/02/2007	01/06/2007	Gaselwest
33	Ieperseweg 87, 8800 Roeselare	01/02/2007	20/04/2007	Gaselwest
34	Zwaanhofweg 1, 8900 Ieper	01/12/2006	01/02/2007	Gaselwest
35	Driewegenstraat 21, 8830 Hooglede	01/09/2006	01/10/2006	Infrax West
36	Grote Veldstraat 114, 8840 Staden	02/07/2005	01/10/2005	Gaselwest
37	Zwevezeelsestraat 142, 8851 Koolskamp	01/09/2004	01/11/2004	Gaselwest
38	Heulsestraat 87, 8860 Lendelede	30/06/2004	01/07/2004	Infrax West

ID digester	Biogas production* [m^3h^{-1}]	Power [kW_e]	Coordinate (WGS84)	Coordinate (WGS84)	Technology, source of biomass
1	4.7	9.7	50.974703	2.757787	mainly agricultural
2	4.7	9.7	50.872444	3.165025	mainly agricultural
3	4.7	9.7	51.117079	3.371116	mainly agricultural
4	972.0	2000	50.810723	3.213015	water treatment plant
5	2244.3	4618	50.787026	3.107737	mainly agricultural
6	684.3	1408	50.887766	2.874851	bio domestic waste with composting
7	291.6	600	50.767909	3.392108	landfill gas
8	3.4	7	51.171293	3.320462	mainly agricultural
9	92.3	190	51.136027	2.901501	mainly agricultural
10	4.7	9.7	50.809993	2.974483	mainly agricultural
11	4.7	10	51.061712	3.393099	mainly agricultural
12	4.7	9.7	51.172906	3.064563	mainly agricultural
13	4.7	9.7	51.056338	2.795272	mainly agricultural
14	4.7	9.7	51.019028	2.675799	mainly agricultural
15	4.7	9.7	51.130663	2.889886	mainly agricultural
16	722.2	1486	50.952965	3.214623	mainly agricultural
17	121.5	250	50.89139	2.646928	mainly agricultural
18	3618.2	7445	51.00788	3.235190	mainly agricultural
19	355.7	732	51.070406	2.687788	other
20	722.2	1486	50.877686	3.098136	mainly agricultural
21	1375.3	2830	50.96243	2.856154	mainly agricultural
22	1111.0	2286	50.887545	2.873835	mainly agricultural
23	959.8	1975	50.983343	3.278749	other
24	521.9	1074	50.917084	3.140121	landfill gas
25	1955.6	4024	50.935677	3.166238	other
26	809.6	1666	50.929197	2.723618	mainly agricultural
27	405.8	835	50.897781	3.108079	mainly agricultural
28	261.0	537	50.873642	3.284037	mainly agricultural
29	183.7	378	51.010167	2.833818	mainly agricultural
30	144.8	298	50.844592	3.294161	water treatment plant
31	1196.0	2461	51.128762	3.308445	mainly agricultural
32	1013.3	2085	50.887802	2.874590	mainly agricultural
33	15.1	31	50.901181	3.124504	mainly agricultural
34	688.2	1416	50.872707	2.876397	mainly agricultural

Table B1 (*continued*)

ID digester	Biogas production* [m^3h^{-1}]	Power [kW_e]	Coordinate (WGS84)	Coordinate (WGS84)	Technology, source of biomass
35	517.1	1064	51.000967	3.074357	mainly agricultural
36	120.0	247	50.962327	3.022453	water treatment plant
37	141.4	291	51.023871	3.208708	other
38	161.3	332	50.876954	3.237328	landfill gas

* Calculated from Power using efficiencies from Table 1.

Appendix C

Electrical power and average costs of electricity, some examples.
See Additional material IV.

Appendix D

Alternative attribution of costs.
See Additional material V.

Appendix E

Hub locations.

Table E1
Hub locations with potential high heat demand [30].

ID hub	City	Address	Coordinate (WGS84)	Coordinate (WGS84)	Potential heat use
1	Roeselare	Oostnieuwkerksesteenweg 121	50.9451757653	3.09557074394	Heat grid; domestic, industrial
2	Ostend	Klokhofstraat 2a	51.2122157928	2.96607573422	Heat grid; domestic, industrial

Figs E1 and E2 show the biogas pipelines in the grid with star layout. The labels refer to labels in Appendix B.

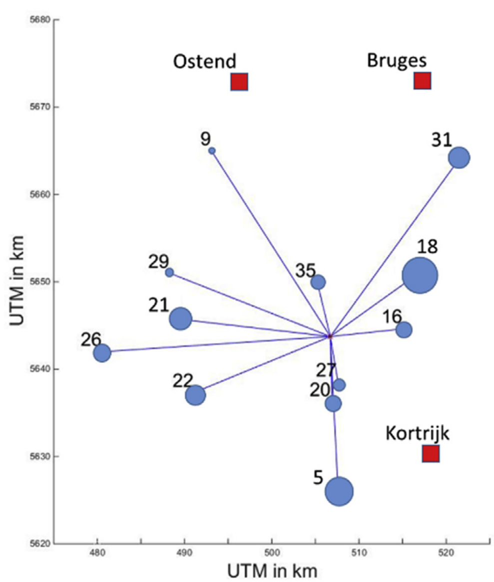

Fig. E1. Grid for hub at Roeselare.

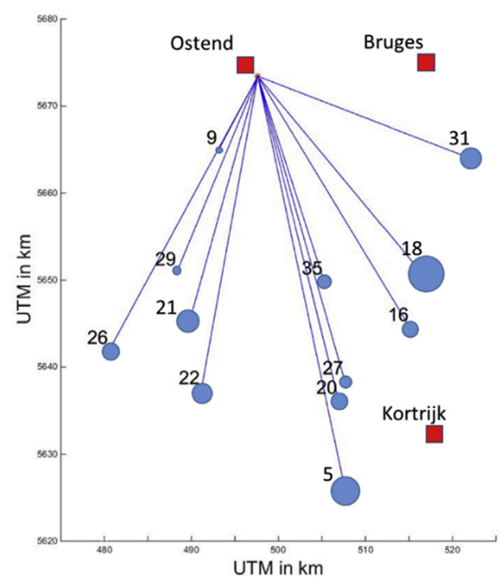

Fig. E2. Grid for hub at Ostend.

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