D6.4 | Guidance for feasibility analysis covering biomethane investment projects - Belgium

Deliverable:	Guidance for feasibility analysis covering biomethane investment projects
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Abbreviations

AD	Anaerobic Digestion
CHP	Combined Heat and Power
CO2	Carbon Dioxide
DM	Dry Matter
DSCR	Depth Service Coverage Ratio
EBA	European Biogas Association
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EBIT	Earnings Before Interest and Taxes
ETS	Emission Trading System
FM	Fresh Mass
GHG	Green House Gas

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REGATRACE in a Nutshell

REGATRACE (REnewable GAs TRAde Centre in Europe) aims to create an efficient trade system based on issuing and trading biomethane/renewable gases certificates/Guarantees of Origin (GO) with exclusion of double sale. This objective will be achieved through the following founding pillars:

- European biomethane/renewable gases GO system.
- Set-up of national GO issuing bodies.
- Integration of GO from different renewable gas technologies with electric and hydrogen GO systems.
- Integrated assessment and sustainable feedstock mobilisation strategies and technology synergies
- Support for biomethane market uptake
- Transferability of results beyond the project's countries

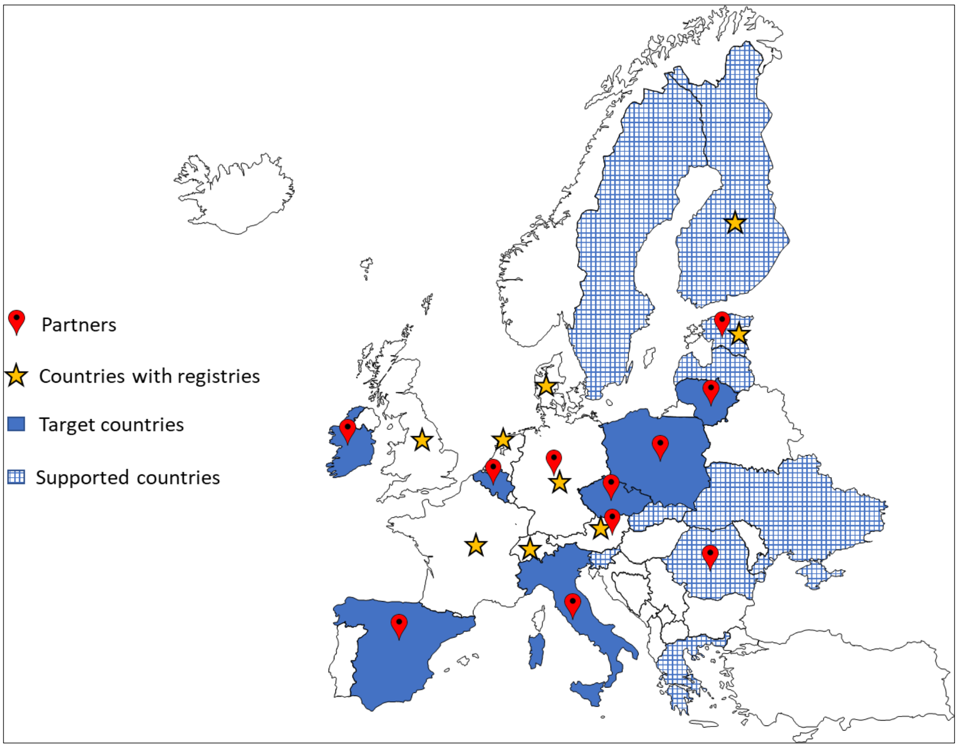

Figure 1: REGATRACE countries and partners

The purpose of this document

This paper has been produced by the European Biogas Assocation in collaboration with Biogas-E, the platform for anaerobic digestion in Flanders, under Work Package 6 of the REGATRACE project (www.regatrace.eu). The Guidance for feasibility analysis covering biomethane investment projects is designed to assist project developers in realising biomethane investment projects based upon the analysis of political, economic, technical, environmental,

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route to market (on or off grid), optimal scale and financial factors influencing the feasibility of the biomethane investment projects.

The document is based on a general guidance on European level and tailored with country specific information by the national biogas association in view of the specific circumstances prevailing in the country. The general guidance has been adapted to local circumstances for enabling direct usage by interested parties in the country. The draft results of the feasibility analysis specific for the country were presented during the third participatory workshop in the REGATRACE project and later – in view of their consolidation – was finally presented during the fourth participatory workshop.

This paper contains **The Example** of cash flow calculations for an **imaginary** biomethane plant with **imaginary** numbers. The related numbers shown in the text and in tables have no practical meaning. They serve exclusively as illustration purposes and must not be used as a reference in any case.

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1 What is a feasibility study?

As the name implies, a feasibility analysis is used to determine the viability of a project idea, ensuring that the project is legally and technically feasible as well as economically justifiable. The feasibility study answers the basic question whether the project is worth the investment. In some cases, a project may not be viable. There can be many reasons for this, including requiring too many resources, which not only prevents those resources from performing other tasks but also may cost more than the investing company/organization would earn by realising a project that is not profitable.

A well-designed feasibility study should offer a comprehensive review of the background of the project, the description of the manufacturing processes the quality and market of the final products, details of operations and management, estimated future market developments, commercialisation of bio fertilisers, monetising of soil carbon sequestration [carbon credits], other bio actives, protein extraction and policies such as Renewable Heat Obligation Scheme, expected financial data, legal requirements, and tax obligations. Generally, the feasibility studies precede technical development, business planning and project implementation.

A feasibility analysis evaluates the project's potential for success, its perceived objectivity is an essential factor in the credibility of the study both for potential investors and lending institutions.

A feasibility study is a study, which is performed by a company/organization to evaluate whether a specific action (investment, acquisition, etc.) makes sense from economic and/or operational standpoint. The objective of the study is to test the feasibility of the specific action and to determine and define any issues that would argue against realising it.

The question a feasibility study should answer is simple: "*Should we proceed with the specific investment project?*" In addition to determining whether the planned project is viable, organizations can use a feasibility study also for understanding the implied risks better.

It is important to remember that a feasibility study is not the same as a business plan. A business plan provides a planning function and defines the actions needed to take a business idea into reality, whereas a feasibility study provides an investigation into a specific investment project under consideration and whether the project is viable.

While it is important to conduct both plans before realising the action, a business plan should only be conducted once the investment project has been deemed viable by a feasibility study.

This Guideline is providing general assistance for conducting feasibility studies for biomethane investment decisions. The main purpose of such feasibility studies is to support/enable.

- taking investment decisions aimed at establishing new biomethane production and
- securing the necessary financing.

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2 Where can the Feasibility study be used?

For investing into new biomethane production facilities two substantially different pathways can be followed:

- expansion of existing anaerobic digestion installation with addition of an upgrading facility (potentially also increasing the raw biogas production),
- investment into new, „green field" complex consisting of anaerobic digestion and biogas upgrading.

This Guidance addressed the issues related to both above mentioned pathways but does not deal with acquisition of already existing and operating biomethane producing installations. The reason for not addressing acquisitions is that in case of existing production the acquisition decision is taken based on actual operational and financial data (cash flow) and not on a general feasibility study.

The primary purpose of a feasibility study is to provide reliable [well-based] data and information to the project developers about the conditions of the project. Subsequently, based upon this analysis the project developers can approach the potential investors and financing institutions.

The feasibility studies assist the project developers also in their communication with the respective authorities, politicians, socio-economic benefits, and impacted communities in securing their support for the project. For this purpose, the study must address in detail the potential risks and the expected concerns by the involved parties.

3 Core elements of a Feasibility study

3.1 Technical feasibility

The first element deals with technical feasibility of the proposed investment, the technical feasibility study will determine if it's a technically viable action.

This part of the feasibility study should answer – for example – the following questions:

- *What raw materials (substrates) are available at what conditions for the anaerobic digestion unit?*
- *Sustainability of agri feedstock substrate?*
- *What is the most appropriate technology to process the raw materials (yields, material balances, etc.)?*
- *What will be the volumes and characteristics of the main product (biomethane) and the by-products (digestate, carbon dioxide, etc)?*
- *What are the regulatory standards surrounding the main product, the by-products, and their use?*
- *What investments are needed for realising the production?*
- *How will the energy consumption of the facility be covered (energy balances, etc.)?*
- *What are the technical conditions for grid connection?*
- *What are the considerations and conditions for the site selection?*

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The above questions can be used both in case of transforming an existing biogas plant to a biomethane producing facility and in case of a new, green-field investment.

3.2 Market feasibility

The second element focuses on understanding the market environment for the proposed investment. It examines issues like whether the main product (biomethane) and the by-products can be placed on the market at reasonable prices or if there is a marketplace for them at all. Regarding renewable energy projects (among them biomethane investment projects) the available national support schemes are of crucial importance.

Market feasibility should answer – for example – the following questions:

- *What market segments are targeted (transport fuel, heating, industry)?*
- *Who are the potential customers and how many of them are there?*
- *How will biomethane and the by-products be sold?*
- *What are the available support schemes and what are the conditions for participating?*
- *Are there realistic export possibilities?*
- *What are the prices and conditions for external energy supplies?*
- *What are the costs of raw material supplies, is there a competition for raw materials?*

Market feasibility is a very important part of a feasibility study when an investment into new production is planned.

3.3 Commercial feasibility

Commercial feasibility is an element of the study focused on the probability of commercial (economic) success. It is mainly focused on studying whether the planned investment can be financed and whether it can generate enough income and profit.

The questions that require answering as part of the commercial feasibility study include, for example:

- *What are the potential sales volumes in different segments?*
- *What is the pricing structure applicable on the market?*
- *How far is the feasibility dependent on state aid (financial support)?*
- *What are the sensitivity points for the business in terms of revenues?*
- *What are the expected financial indicators of the investment project (IRR, NPV, PI, DSCR)?*
- *How much own funds are required to realise the investment and start operating?*
- *What are the conditions for securing external finance?*

3.4 Overall risk assessment

The fourth element focuses on the major risks the proposed investment plan can entail. The overall risk assessment part of a feasibility study examines the different ways the project company (the investor) can reduce the risk of embarking on the new venture.

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The overall risk assessment should answer the following questions:

- *What are the major risks associated with the operation?*
- *What is the survival outlook for each of the above risks?*
- *Merits of a National co-ordination and design authority to support ongoing and continuous improvements to AD biomethane developers, market exploitation, new products/innovative technology research, management support services?*
- *How sensitive are the profits?*
- *What are the best ways to minimize these risks?*

The aim is to try to cover all the possibilities and create a risk assessment map, which deals with the probability of the risk and the impact it would have on the project. It's aimed at recognizing the risks that can make or break the project from the smaller, more manageable risks.

4 Key factors for successful project development

The different (political, technical and financial) factors influencing the feasibility of biomethane production are addressed in several chapters of this paper. Here we place only a short summary to assist the reader on focusing on the main issues.

- Bridging the funding gap between the prevailing natural gas prices and the costs of biomethane production is the biggest challenge for every biomethane project. Measures can and should be taken to lower the costs of investment and operation as much as possible, but the business plans must not assume that achieving natural gas parity is only a question of time. The biomethane projects remain dependent on political support **stable, long-term political commitment** towards renewable energy deployment and – specifically – towards utilisation of biodegradable feedstock for biogas/biomethane production.
- Among the operational costs of biomethane production the **costs of raw material supplies** have a decisive importance. The project developers must assess the present and future biodegradable [raw] material supply possibilities very carefully and should elaborate alternative plans to handle any disruption. If possible, it is advisable, that the owners of raw materials (for example agricultural producers, food/beverage industry or waste management companies) are involved in the biogas/biomethane projects as shareholders – to secure their long-term interest in backing-up the venture, under pinned by off take agreement for biomethane.
- Project developers should never assume that the raw material supply patterns remain unchanged through the 15-20-25 years lifetime of the project. It is strongly advisable to install **technologies** which have the needed flexibility to adjust to changes in raw material composition. Under these considerations the basic engineering plan of the facility must foresee place/connections for adding equipment in the future, detail design preconstruction.

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- In any case, **locations** offering guaranteed long-term sustainable substrate supplies must be preferred. The best chances are on places where the feedstock is co-located with infrastructure, deep integration to respective agricultural or industrial activities is possible (for example: co-location of animal slurries/manures, sugar factories, breweries, etc.). The distance to an existing gas grid must be carefully evaluated.
- Organic **waste streams** (collected source separated) offer good possibilities for installing biogas/biomethane facilities but only if the future competition with other biogas/biomethane plants for the material can be avoided [excluded]. (The experience shows that the gate fees paid by organic waste owners tend to decrease and even disappear with the increasing number of biogas plants in the region.)
- Mature and efficient anaerobic digestion and biogas upgrading technologies are available from several technology suppliers. There is a strong competition among these companies today which puts investors in good negotiating position. With selection of **proven and reliable technology** future operational difficulties can be avoided. It happens quite often that the investors focus too much on the purchase price and do not consider other important elements, like the performance guarantees and operational support services offered by the supplier(s). These should be negotiated as part of the initial package and where possible consider "Clustering of AD plants" in negotiating Capex and O&M contracts.
- The **long-term placement [biomethane purchase agreement – BPA]** of produced biomethane must be secured from the start in view of underpinning the project, the existing political priorities, and financial incentives. From this viewpoint regions with developed CNG-LNG fuelled transportation are especially attractive. Long-term supply agreements with companies distributing gas for heating can also serve as a solid base for an investment decision. A successful and bankable BPA can be secured either thanks to a feed-in-tariff or feed-in-premium systems, or a biofuels quota system where obligated parties have an incentive to commit purchasing biomethane long-term avoiding paying penalties.
- The **placement of the fermentation residue [digestate or bio fertilisers]** from the anaerobic digestion is a key issue of any successful biomethane project. As a function of local agricultural conditions, digestate can be a revenue although minimal, or a cost to the biomethane plant, depending on the value of organic fertiliser, the possible contaminants to be eliminated, possible local excess of nitrogen in the soil etc. The residue is usually separated into a solid and a liquid fraction. The solid fraction can be used as organic fertiliser and – as such may even have a market value. The liquid fraction causes no problem if sufficient cultivated arable land is available in the vicinity of the biogas plant for spreading it on the fields or further processed as a bio active/stimulant. In absence of such possibility the liquid fraction needs to be processed, i.e., cleaned to a status accepted for letting it out into the nature. Such treatment of the fermentation residue triggers extra

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investment and operational costs, which may have a negative impact (5-10€/t) on the feasibility of the venture.

- The **liquefaction of biomethane** can prove to be an interesting alternative, either because the gas grid connection is too costly/too weak to offtake the gas, or because the off takers are ready to pay a premium for bio-LNG which is the form of biomethane offering best storage options for maritime & heavy trucking. This deserves to be studied for plants above 500 Nm^3/h to afford the significant extra capex/opex which amounts to 10-15€/MWh.
- **Good communication to local stakeholders** is key to prevent NIMBY issues, especially in densely populated areas. Studying and communicating the positive impacts of the biomethane plant is relevant herein, such as job creation, economic value creation in rural territories, chemical fertilisers avoided, waste treated etc. Furthermore, transparent communication about odour and traffic control is advisable.

5 CASE B – converting an electricity generating AD plant to a biomethane producer

This Guideline is focusing on the feasibility of a “green-field” biomethane investment project. Nevertheless, biomethane investment may take place in an existing biogas plant, which has been generating electricity in local CHP, but the FIT/FIP period has expired and producing electricity in not economic anymore.

A feasibility study in this case is also necessary to determine the expected economics and provide the base for securing the financing, taking bank credit to cover the additional investment costs.

Regarding adding an upgrading unit to the existing AD unit, the technical project should address – among others – the following questions:

- which revamping measures are necessary to extend the lifetime of the AD unit?
- is it possible to increase the biogas production capacity?
- if yes, which additional investments are needed in the AD unit (e.g., for receiving the additional substrates, adding pre-treatment/mixing, pumping capacity, etc.)?
- is the existing biogas desulphurisation solution acceptable for the upgrading unit or new desulphurisation unit must be installed?
- is there sufficient space available for installing the upgrading unit (space limitation may influence the selection of the upgrading technology)?
- which part of the electricity generation equipment (CHP) will remain in operation to supply electricity to both the AD and upgrading units?
- what are the technical conditions for natural gas grid connection on the location (pressure, etc.)?

Contrary to the case with a green-field new biogas + upgrading project the feasibility study for the conversion project may apply the series of practical data generated during the operation

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of the AD unit, such as actual substrate costs, biogas yields, biogas quality, energy consumption, digestate quality and placement, achieved full-load operating hours etc. This is very important while banks are usually concerned about the so called "biological risk", i.e. the risk of proper functioning of the biological system in the digesters.

The financing of the conversion project is substantially different from the green field AD + upgrading project, while in this case the owner/investor is not expected to provide fresh financial funds, the exiting assets should be sufficient.

It is to be checked whether a non-returnable investment subsidy would be available in the country where the AD unit is already in operation, e.g., a renewable heat obligation scheme (Article 23).

In lack of state financial aid (non-returnable investment subsidy) the needed additional investments will be partially covered by capital grant funding and balance with bank credit.

The cash flow calculation presented in **The Example** for a green field biomethane project can be adopted to the conversion project through.

- replacing the estimated biogas production related data with actual, practical data from past operation,
- considering that certain components of the AD unit have already been depreciated,
- considering the additional investments needed for the AD unit,
- considering the remaining lifetime of the AD unit.

6 Technical feasibility

6.1 Biogas substrates and biogas production forecast

Securing substrate supplies and elaborating reliable and prudent forecast for these supplies is probably the most important element for developing and realising an anaerobic digestion (AD) based biomethane project. The volume, quality, and costs of proposed substrate, either processed or agri-crops feedstock, determine the engineering and the biogas producing capacity of the AD plant and substantially influence the feasibility of the project.

6.2 Basic considerations

When selecting the raw materials (substrates) for biogas production several factors must be taken into consideration, such as:

- Regulatory - sustainability,
- technical,
- by products potential
- economic.

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6.2.1 Regulatory aspects

a) Food/feed crops

Food/feed crops are defined in the RED II as follows:

"Food and feed crops" means starch-rich crops, sugar crops or oil crops produced on agricultural land as a main crop excluding residues, waste or ligno-cellulosic material and intermediate crops, such as catch crops and cover crops, provided that the use of such intermediate crops does not trigger demand for additional land.

Article 26 of the RED II contains specific rules for biomass fuels (including biogas) produced from food and feed crops.

In several European countries regulatory limitations are in force in relation to the share of food/feed crops which can be processed in a biogas installation. In **Belgium**, the use of food and feed crops as a feedstock for biogas production is allowed and not limited. However, the use of these types of energy crops can have an effect on the eligibility of a project to apply for subsidies or the height of the subsidies.

At the time of writing, with the ongoing institutional debate on the Renewable Energy Directive revision, the co-legislators position haven not heavily impacted the text of Art. 26 of food and feed crops utilisation. With higher GHG emissions savings thresholds to comply with in the Heating and electricity sector, the market for substrate with better GHG emissions performances will further develop.

b) Animal by-products

Animal by-products (ABPs) are materials of animal origin that people do not consume. ABPs include among others:

- Animal feed - e.g., based on fishmeal and processed animal protein,
- Animal slurries/manures - Organic fertilisers and soil improvers - e.g., manure, guano, etc
- Technical products - e.g., commercial food waste, by products from food and drinks processing plants, pet food, hides and skins for leather, wool, blood for producing diagnostic tools.

ABPs emerge – for example – from slaughterhouses, plants producing food for human consumption, dairies and as fallen stock from farms.

ABPs can spread animal diseases (e.g., BSE) or chemical contaminants (e.g., dioxins) and can be dangerous to animal and human health if not properly disposed of. The EU rules regulate their movement, processing, and disposal. In Ireland, pasteurisation is standard requirement to mitigate the risks associated, the Department of Agriculture have categorised three types of AD plants, and application for licence is required to operate an AD plant.

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ABPs are categorised according to their risk using the basic principles in Regulation (EC) 1069/2009[1] and Commission Regulation 142/2011[2]. These regulations also contain the rules for processing ABSs in anaerobic digesters of the biogas plant.

Regulation (EC) 1069/2009 has been transposed to the domestic legislations of the EU member states.

ABPs are arranged in three groups according to their health risk. ABPs in category 1 are considered to have the highest risk and are excluded as feedstock for digesters. ABPs in categories 2 or 3 are less of a hazard to the public health and are allowed as a feedstock.

In order to effectively use ABPs as a feedstock, a plant owner has to receive an admission from the regional administration. In Flanders, OVAM is responsible for the admissions when primarily waste streams are used. When manure is used, VLM Mestbank is authorized. In Wallonia, this is the responsibility of the Direction Générale Opérationnelle Agriculture, Ressources naturelles et Environnement (DGO3).

From 1 January 2022 forward, manure treatment and processing installations must be equipped with flow meters to monitor the liquid manure streams. This is only the case for Flanders.

c) Substrates accepted for “advanced fuel” production.

The Royal Decree of 7 December 2021 (concerning the determination of product standards for transport fuels from renewable sources and for transport fuels based on recycled carbon), published in the Belgian Official Gazette, regulates the product standards for transport fuels from renewable sources. This RD replaces the one of 8 July 2018.

RED II contains specified targets for the share of “advanced fuels” in the total fuel consumption in transport. In case the transport fuel use of biomethane is targeted, focusing on this list of Annex IX Part A is much desirable. (See English and Dutch translation of the list in Annex 1 of this document).

Annex IX is currently under revision and an updated draft version will be soon published by the European Commission services; the draft delegated act will be then submitted to the scrutiny of co-legislators.

Note that Belgian legislation permits the double counting of advanced biofuels, but biomethane is currently not considered as a possible resource to comply with this target. Only biodiesel and bioethanol are registered.

d) Sustainability requirements

[1] *REGULATION (EC) No 1069/2009 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 21 October 2009*

[2] *COMMISSION REGULATION (EU) No 142/2011 of 25 February 2011 implementing Regulation (EC) No 1069/2009 of the European Parliament and of the Council laying down health rules as regards animal by-products and derived products not intended for human consumption and implementing Council Directive 97/78/EC as regards certain samples and items exempt from veterinary checks at the border under that Directive*

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The sustainability requirements must also be taken into consideration. Among the sustainability related requirements (detailed in Article 29 of the RED II) the data on greenhouse gas emission intensity are the most important.

According to Article 29. para 10. of RED II the greenhouse gas emission savings from the use of biofuels, bioliquids and biomass fuels shall be:

- at least 65 % for biofuels, biogas consumed in the transport sector, and bioliquids produced in installations starting operation from 1 January 2021.
- at least 70 % for electricity, heating and cooling production from biomass fuels used in installations starting operation from 1 January 2021 until 31 December 2025, and 80 % for installations starting operation from 1 January 2026.

The GHG emission savings are to be demonstrated in comparison with the relevant fossil fuel comparators. RED II imposes different GHG emission reduction thresholds depending on the field of application. For example:

- for biomass fuels used as transport fuels the fossil fuel comparator shall be 94 g CO_2eq/MJ,
- for biomass fuels used for the production of electricity the fossil fuel comparator shall be 183 g CO_2eq/MJ electricity,
- for biomass fuels used for the production of useful heat, as well as for the production of heating and/or cooling, the fossil fuel comparator shall be 80 g CO_2eq/MJ heat.

Annex VI of RED II contains the „Rules for calculating the greenhouse gas impact of biomass fuels and their fossil fuel comparators". In the Annex default values are also provided for some biogas substrates (manure, maize whole plant, biowaste). In lack of default values, the GHG emission is to be calculated, the methodology is detailed in Annex VI. Preference is for actual figures calculated, more robust and reliable data/information on GOs for gas consumers. Sustainability criteria has proposed 40% animal slurries with 60% agri-feedstock, substrate of grass silage/mixed species pasture.

When planning the biomethane investment the GHG emission caused by the production and transportation of biomass (processed in the AD unit) must be considered. BIOSURF Deliverable 5.3. Methodology for the calculation and certification of GHG emission caused by the production of biomethane (in the whole Life Cycle) [3] provides assistance.

More information on sustainability for the specific case of **Belgium** can be found in Section 7.3.

6.2.2 Technical aspects

The AD equipment must be engineered and dimensioned in accordance with the volume and estimated quality of the substrate input – also considering potential seasonal changes in composition and quality. Separately, the upgrading technology will influence the optimum scale of AD biomethane plant.

[3] *http://www.biosurf.eu/en_GB/downloads-and-deliverables/deliverables/*

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The characteristics of the to be processed substrates determine the technology of the anaerobic digestion unit, the basic engineering must correspond to the envisaged substrate composition. For example:

- certain substrates require pre-treatment before the digester, such as cutting (sizing), thermal treatment, etc. Such requirements are especially important for animal by-products,
- the equipment for forwarding the materials into the digesters must correspond to the characteristics of the substrates,
- the mixing equipment is to be designed in view of the characteristics of the substrates,
- the necessary volume of the digesters must provide for sufficient retention time for complete degradation.

Under normal anaerobic digestion process, the volume and composition of substrate input mix determines the volume and composition of digestate. The placement of digestate is one of the most important challenges in an AD/biomethane investment.

6.2.3 Economic aspects

When selecting the raw materials (substrates) for biogas/biomethane production a special attention is to be given to the possibility of processing different organic waste streams and other materials of zero or low value market value (for example: manure, slurry, thin fraction of separated stillage from bioethanol production, waste streams from sugar and food processing industries, food waste etc.). Utilising organic waste streams have pros and cons. On the positive side, the supply costs are lower, the GHG emission reduction effect is higher and, in some cases, even “gate-fee” type income can be realised. On the negative side, the volume of these materials is usually relatively low, their composition fluctuates with time and season, and they demand additional treatment facilities. The feasibility study has to address realistically both the positive and negative impacts.

During the preparation to the investment the volume, quality and biogas potential of these organic waste streams must be thoroughly checked. The waste materials have no standard quality, and it is quite difficult to take representative samples for laboratory analysis. For these reasons, the biogas yields forecasts must be treated with reservation.

As it is also illustrated in **The Example**, the costs of substrates are the most important single component in the total cost of biomethane production and the reliability of related data is a pre-condition of an acceptable feasibility study (and later of a successful project).

6.3 Biogas production forecast

The substrate supply forecast must be reliable both in relation to volumes and biogas potential. (The specific methane yield is expressed in Nm^3 methane generated from 1 kg organic matter).

The data for the biogas yields can be taken from several sources:

a) for usual substrates, the biogas/methane yield data can be found in the literature. For example, the independent German institution KTBL (Kuratorium für Technik und

Bauwesen in der Landwirtschaft) publishes recommendations ("Richtwerte") for planning biogas and methane yields from different substrates.[4]

b) laboratory analysis of representative samples,
c) data received from other biogas plant processing the same materials,
d) data provided by specialised companies offering AD technology, consultancy, biotechnological service, etc.

In this Guidance we provide **The Example** of cash flow calculations related to the feasibility of biomethane investment. The numbers applied in **The Example** are imaginary and must not be used as a reference. The only purpose of showing this **Example** is to assists the readers through illustration.

In **The Example** the substrate input is imagined as shown in the table below, which also illustrates the calculation of estimated biogas production:

Table 1: Biogas production forecast

	Volume	DM	oDM	Biogas	Biogas	Methane	Methane
	to/year	%	%	Nm³/to oDM	Nm³/year	%	Nm³/year
Cattle slurry	30.000	8,0	85,0	350,0	714.000	55,0%	392.700
Poultry manure	15.000	30,0	75,0	500,0	1.687.500	55,0%	928.125
Biowaste	5.000	30,0	85,0	550,0	701.250	52,0%	364.650
Maize stover	7.000	65,0	82,0	580,0	2.163.980	51,0%	1.103.630
Catch crops	10.000	27,0	92,0	620,0	1.540.080	53,0%	816.242
Maize/sorghum silage	15.000	32,0	93,0	650,0	2.901.600	52,0%	1.508.832
Recirculation	20.000	5,0	30,5				
Total/average	102.000	21,0			9.708.410	52,7%	5.114.179

where:
DM – dry matter content
oDM – organic dry matter share in total DM
Nm^3 – The volume of any gaseous material at temperature: 0 °C, and pressure: 1.01325 barA.

Note: the volume of energy crop silage has been determined considering 8% loss at ensilaging.

The specific costs of individual substrates per unit of produced methane is a good indicator for identifying both the economically most attractive and most problematic substrates. This indicator also assists in addressing the economic impact when one or more substrates must be replaced.

Table 2: Biogas substrate cost forecast

	Volume	Methane	Substrate cost	Substrate cost	Substrate cost
	to/year	Nm³/to FM	EUR/to	EUR/m³ CH_4	EUR/year

[4] *Gasausbeute in landwirtschaftlichen Biogasanlagen Heft 107 Jahr 2015 3. Auflage www.ktbl.de;*

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Cattle slurry	30.000	13,1	2,0	0,153	60.000
Poultry manure	15.000	61,9	10,0	0,162	150.000
Biowaste	5.000	72,9	15,0	0,206	75.000
Maize stover	7.000	157,7	15,0	0,095	105.000
Catch crops	10.000	81,6	28,0	0,343	280.000
Maize/sorghum silage	15.000	100,6	32,0	0,318	480.000
Total/average	82.000			0,225	1.150.000

where:
FM – fresh mass

Important questions to be answered in the feasibility study are the following:

a) are the applied biogas yields realistic?
b) are long-term supply agreements possible?
c) what are the risks of one or more substrates becoming unavailable?
d) will alternative substrate sources be available in case of disruptions with originally foreseen supplies?
e) has the deterioration of quality and loss of biogas potential with storage time been considered?
f) Is the necessary C:N ratio in the substrate supply mix secured?

6.4 Comments on substrates

Any feasibility study covering a biomethane investment project must contain the description of the substrates foreseen for processing in the anaerobic digestion unit. Without demonstrating the understanding of the specifics of the substrates the feasibility study will not be seen as reliable and trustworthy. Several examples are provided below.

a) <u>Agri crop feedstock (multispecies/grass) silage</u>
Assuming best practise methods and cross compliance regulations are applied, the use of dedicated Agri crops as feedstock for the biomethane production can be sustainable, such as multispecies pastures. The fact that these raw materials are characterised by the highest yield and area efficiency should not be neglected.

In **The Example** 32 EUR/tn was applied as the imaginary average cost for agri-crop silage. In Belgium, the average cost for maize including silage amounts to about 47 EUR/tn. However, this number may vary a lot. In practice, long-term supply agreements must be concluded between the biogas/biomethane plant and the farmers to ensure stability and sustainability for both parties. The farmers gain secured income at fixed price, while the biogas/biomethane plant receives guaranteed substrate supplies at fixed price. Excluding the fluctuation of agri-crop prices is beneficial for both parties in the long run.

In the above-mentioned supply agreements, the following factors must be taken into consideration:

- the fixed price of agri-crop silage paid by the biogas plant to the farmers must be linked to the quality, preferably to the methane potential of the supplied material – ad adequate system is to be developed and agreed between the partners,
- for a replacement crop the same principle is to be applied: for example, if the methane potential of the crop is 10% less, than its price should be also 10% less.

b) Animal slurries

Animal husbandry results in the by-production of animal slurries, also called agricultural primary residues or animal slurries. The slurries can be used as raw material for biogas and subsequently biomethane production. However, only slurries generated from indoor housing can be obtained for energetic purposes. The main part of animal manures from sheep, goats, horses, gooses, and ducks is not usable for energy applications due to the high proportion of free-range systems of these animals. In Europe big quantities of animal slurries from indoor housing originate from cattle and pig farming, less from poultry farming. Manure from chicken/poultry is used in biogas plants in limited amounts because of its high ammonia content.

Animal slurry can be subdivided in two main groups: liquid and solid fraction. “Slurry” is animal manure in liquid form, consisting of water with solid matter and urine of domestic animals, including possibly also small amounts of litter. “Manure” is a mixture of excrements of domestic animals which includes materials of animal bedding such as straw or wood chips. The biogas potential of animal slurry (both solid and liquid) depends partially on the food quality (fresh/liquid fodder, dried fodder). The yields for biogas and methane differ between slurry and manure and between animal species but also depend on the age of the animal slurry (outgassing).

Animal slurry can be used for the commercial energy production on and near the farms, without transportation on long distances. The material is easy to ferment, and the fermentation residue (digestate) can be applied as organic fertilizer. Significant advantages of the fermentation residues compared to untreated animal slurry are the reduced odour emissions, the homogenization of the substrate which makes it more readily spreadable, increased proportion of inorganic nitrogen which satisfies better the nutritional needs of plants, fewer pathogens and weed seeds.

In **The Example** 2 and 10 EUR/tn was applied as the imaginary average cost for cattle slurry and poultry manure specifically. In Flanders, the average cost for manure amounts to 8,05 EUR/tn (VEKA-report 2022). In Wallonia, the nitrogen content of the livestock effluents is an important factor for the price setting.

c) Biodegradable organic waste

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Other (than animal excrements) organic biodegradable materials are defined under the Waste Framework Directive[5]: „bio-waste" means biodegradable garden and park waste, food and kitchen waste from households, restaurants, caterers and retail premises and comparable waste from food processing plants.

Although efforts have been made to reduce the amount of bio-waste from households in some member states, there is still a considerable amount of bio-waste derived from food-, feed- and beverage production and consumption that cannot be avoided. One of the best options for dealing with these organic waste streams is processing them in biogas plants producing energy and organic fertilizer.

Certain bio-waste streams, mainly from beverage and food processing, have a competing application, they can be also used as fodder (or component to fodder). As long as these materials (for example: spent grains from ethanol production, rape-seed press cake from biodiesel production, sugar-beet press cake etc.) find place on the animal feed market, the income there is substantially higher than the value generated through anaerobic digestion.

The landfilling of biodegradable organic waste from households is forbidden. The bulk of the separately collected bio-waste from households is currently still treated in composting plants. Due to further regulations and developments in the biogas sector, an increasing amount of bio-waste material from this category can be expected for digestion.

The term "residue" comprises very different types of biodegradable materials. All of them have in common that they are by-products and were originally not intended to produce bioenergy. Besides municipal and agro-industrial bio-degradable materials and animal slurries, this biomass category also includes crop residues (mainly straw), residues from landscape maintenance and conservation, incl. pruning material and catch crops.

The revision of legislative documents on biodegradable materials/waste has been completed in the European Union. The revised legislation on waste set clear targets for reduction of waste and establish the long-term path for waste management and recycling. Key elements of the revised waste package include:

- a common EU target for recycling 65% of municipal waste by 2030.
- a binding landfill target to reduce landfill to maximum of 10% of municipal waste by 2030.
- a ban on landfilling of separately collected waste.
- promotion of economic instruments to discourage landfilling.

The new waste legislation is clearly promoting the source separated collection of bio-degradable materials and treats anaerobic digestion as the preferred method of recycling. The recycling targets combined with strict limitations on landfilling create serious challenges in those countries, regions and communities which still landfill the bulk of the municipal waste.

[5] *Directive (EU) 2018/851 of the European Parliament and of the Council of 30 May 2018 amending Directive 2008/98/EC on waste (Text with EEA relevance)*

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The municipalities in Europe are expected to take strong measures towards source separated collection and recycling. Processing the organic material for biomethane as the target product will be increasingly attractive, while in this way clean fuel can be provided for the local fleets of buses, waste collecting and street cleaning machinery and other vehicles.

In **Belgium**, the use of biowaste from households is restricted. To reduce the spreading of possible pathogens, the digestate of organic municipal solid waste (OMSW) should be treated in a composting facility for two to four weeks. As a results, OMSW is not mixed with other types of feedstocks and treated in specific biogas plants.

Starting from 2021, companies and organisations who produce significant amounts of kitchen waste are obliged to organise source separated waste collection. In 2024, this obligation is extended to all companies in Flanders.

In **The Example** 15 EUR/tn was applied as the imaginary average cost for biodegradable organic waste. In Flanders, the average cost for this waste amounts to 11,9 EUR/tn (VEKA-report 2022). However, the value will strongly depend on the type of material.

d) Crop residues

Crop residues are parts of the crop that are not harvested during standard agricultural operations. Significant amounts of agricultural residues remain on the field after harvest. The utilisation of these residues (also called by-products from agriculture) depends on several factors: types of crops, crop rotation, crop mix, agricultural practices, harvesting technics. There are considerable differences in Europe regarding cultivated area, types of crops and yields due to climate and soil conditions, accessibility, and farm practices.

Straws from cereal, maize and rapeseed production are the main crop residues, which are already used for many different purposes. The majority of the available (cereal based) straw is used for animal housing, it can be collected for CHPs, wheat straw is already used for bioethanol production, other biomass-to-liquid technologies are under development. Substantial part of straw remains on the field for keeping soil fertility. In view of its characteristics corn stover is much more suitable for anaerobic digestion than wheat straw and has fewer competing usages – for these reasons among crop residues corn stover is the most prospective resource for the biogas/biomethane industry.

Corn stover (straw) is not a traditional substrate for the biogas plant. The processing of corn straw (stover) in the biogas plants is a relatively new development in the industry which is continuously searching for low-cost substrates. This dry material with high celluloses content is not easily available to the microbes participating in the anaerobic digestion process and – for this reason – it must be pre-treated before entering the digester. Different companies have developed different approaches, including the application of mechanical, chemical, and biological methods. Only a few biogas technology companies have ready solutions for processing this material.

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The harvesting of corn stover for the biogas plant requires special equipment (different from the usual corn harvesting machines), the costs must be foreseen in the investment budget of the project.

The average yield of corn stover is about 7 tons/hectare, so the volume included in the Example could be collected on about 1.000 hectares.

There are many other primary residues that can supply bio-degradable materials for bioenergy such as cuttings of permanent grasslands which are sometimes found on agricultural lands (in this case usually used for hay or silage production and its further use in animal husbandry), but which also originate from parks or other recreational areas, nature conservation areas or dykes and abandoned grasslands. Management of abandoned areas through cutting can be beneficial for biodiversity.

e) Catch crops/cover crops/second crops.

Catch crops (cover crops, second crops) are cultivated on the same piece of arable land before or after the main crops. These crops are mostly used to bridge the time in between main crop cultivations when the area would otherwise just consist of delicate fallow land. In this context catch crops/cover crops help to prevent water and wind erosion, nutrient leakage, and the consequent soil deterioration. Table 3 lists some of the plants which can be cultivated as catch crops/cover crops.

Table 3: List of potential catch crops/cover crops

Winter barley	Hordeum vulgare
Winter triticale	Triticum x Secale
Winter oat	Avena sativa
Sunflower green	Helianthus annuus
Rye green	Secale cereal
Mustard green	Sinapis alba
Summer barley	Hordeum vulgare
Summer oats	Secale cereal
Summer triticale	Triticum x Secale
Oilseed radish	Raphanus salivus
Phacelia	Phacelia tanacetifolia

6.5 Anaerobic digestion

This section of the feasibility studies is addressed to those readers (mostly financial people) who may not have detailed knowledge of the biogas technology and may have concerns about getting involved with a biological technology (which seems to be more difficult to operate than physical or chemical processes). In addition, the section also assists the project developer in formulating the inquiries to the technology suppliers, to go through the phases of the technology and to control whether all important elements have been included.

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There is a big variety of biogas fermentation technologies on the market offered by specialised technology engineering companies, some of them having a proven track record with reference lists and confirmed performance, others at the early stage of development and practical application experiences.

The technological solutions differ from each other in the following key elements:

a) Pre-treatment of substrates
b) Wet/dry fermentation
c) Number of fermentation stages
d) Digestion temperature
e) Digester configuration
f) Mixing equipment (agitators)
g) Desulphurisation
h) Biogas storage

6.5.1 Pre-treatment of substrates

The need from pre-treatment is very much substrate dependent. For example, the biogas plants fermenting animal by-products, animal waste (like slaughterhouse waste) must obey the relevant regulations, must cut the material to prescribed particle size and must carry out thermal hygienisation [pasteurisation].

There are several methods to pre-treat the substrates of vegetable origin also, like ultra-wave treatment, thermodynamic (heat and pressure) treatment, bio extruders, etc. Most of these technical approaches have appeared recently and need to be proven in the practice both in practical and economic terms.

In view of the assumed composition of substrates in **The Example** the pre-treatment is limited to sizing: one cutting equipment is needed for bringing the cattle manure (with straw) and the substrates of vegetation origin down to particle size of max. 40 mm [20mm in Ireland].

6.5.2 Wet/dry fermentation

Most of the agricultural biogas plants apply wet fermentation, which means that the dry matter content of the fermentation mass is in the range of 6 – 15%. This offers the natural environment to the microorganisms "working" in the system. In view of the assumed substrate composition in **The Example** it is not necessary to consider dry fermentation.

The wet anaerobic digestion (AD) process is applied to liquid waste streams that are conveyable by liquid pumping. The wet AD process can be done in reactors of two main configurations, continuously stirred tank reactors (CSTR) and plug flow reactors. The theory of the CSTR is that, through continuous mixing, the composition of the contents of the reactor in any given spot in the tank is the same as in any other spot in the tank. The theory of plug flow, on the other hand, is that the makeup of the contents at the head of the digester is different than that of the material leaving the digester just as the material flows through the digester in the pattern like a plug through a pipe. For the start of the systems, liquid cattle manure, or fermentation mass from the digester of an operating biogas installation (inoculum) is needed to provide the initial stock of microbes participating in anaerobic digestion.

6.5.3 Stages in fermentation process

The biogas plants operating on wet fermentation basis differ from each other regarding the number of process stages. There are plants, where the fermentation is realised in a single stage (that means that all substrates enter a single digester, and the fermentation residue is taken out of this digester). Depending on the volume of substrates there might be more than one digester running parallel to each other in one-stage fermentation systems.

In the two-stage solutions the substrates are fed-in into the first stage digester (often called main digester) and the fermentation mass is thereafter forwarded to the second stage digester (often called post-digester). The advantage of such digester configuration is that higher level of biodegradation of organic material (i.e., higher specific biogas yield) can be achieved.

The Fachagentur Nachwachsende Rohstoffe e.V. (FNR) has carried out a Biogas Measure Program under the appointment of the German Ministry for Nutrition and Agriculture. They have analysed the data from 61 biogas plants and concluded that the remaining biogas potential in the fermentation residue of one-stage fermentation plants can be nearly two times higher than in the two-stage processes. In the FNR study the average remaining biogas potential was 9,5 Nm^3 CH_4/to in one-stage plants as compared to the average of 4,9 Nm^3 CH_4/to in the two-stage plants.

There are biogas technology companies offering 3 stage systems. The first stage in these plants is operated at low pH value and is destined for the hydrolysis step in the biological process chain. It is to be considered whether the additional investment- and operational costs are justified for typical agricultural substrates.

6.5.4 Fermentation temperature

The biogas plants operated with agricultural feedstocks apply different fermentation temperatures:

- Most of the units are operated at the so called “mesophilic” temperature range, which is 38 +/- 3 °C - the biological system is most stable at this temperature.
- Operating the fermentation at “thermophilic” temperature (54 +/- 2 °C) is more efficient but also more demanding (for example the regulation of the temperature in the digesters must be more precise and reliable);
- There are few biogas plants that combine a mesophilic stage with a thermophilic stage – this cannot be desirable from the viewpoint of the biological system, while totally different microbes live and “work” at the different temperatures.

One possible approach is to determine the size (active volume) of the digesters calculating with mesophilic fermentation conditions but installing digester heating system and insulation, which would enable to run the plant at thermophilic temperature range in the future. By doing so, a reserve capacity could be established at low cost and with no risk.

6.5.5 Digester configuration

The digesters are placed either horizontal or vertical. The horizontal digesters might have a rectangular of a cylinder form, while all vertical digesters are cylinders.

The digester configuration, the feed-in systems and the mixing equipment are essential parts of proprietary anaerobic fermentation technologies and – as such – are determined by the selected technology partner.

6.5.6 Digester dimensions

A key design parameter for any digester system is the overall organic matter loading rate. For any given project, no two digester suppliers will provide a system of the same size. Loading rates are commonly expressed as the average number of days of retention time and/or the quantity of organic matter introduced to a given tank volume per day.

Under “organic load” we understand the quantity of organic dry matter (oDM) loaded into the unit volume of the digester daily expressed in kg oDM/m^3/day. In **The Example** a conservative organic load rate of 3,5 kg oDM/ m^3 digester volume/day was applied, although up-to-date agricultural anaerobic digestion systems may operate also at substantially higher rates.

The hydraulic retention time (HRT) indicates the number of days substrates remain in the digester(s) on average. In **The Example** the average HRT was estimated as 60 days (just for illustration) and this requirement has increased the needed digester volume (see Table 4.)

Table 4: Digester volume estimation

Organic dry matter (oDM) input	to/year	17.369
Average organic dry matter (oDM) input	kg/day	47.586
Allowed organic load (for planning purposes)	kg oDM/day/m^3 digester	3,5
Digester volume recommended based on organic load	m^3	13.596
Input volume	m^3/day	279
Average hydraulic retention time (HRT)	days	60
Digester volume recommended based on HRT	m^3	16.767
Recommended digester volume, min.	m^3	16.767

Assuming 17.000 m^3 digester volume in **The Example** results in the following indicators: [RGFI have an optimum size plant at 35,000/t pa, 40% animal slurry and 60% agri feedstock [substrate]

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Table 5: Digester dimension indicators

Digester volume	17.000	m^3
HRT (average)	60,83	days
Organic load (average)	2,80	
Biogas production	1,56	m^3/m^3/day

Showing these indicators in the feasibility study will strengthen the confidence of the addressees that the anaerobic digestion system has been designed with due diligence. For example, the specific biogas production of 1,56 Nm^3/m^3 digester volume indicates that at 17.000 m^3 digester volume the fermentation system will have reserve capacity.

6.5.7 Mixing technique (agitators)

The proper mixing of the fermentation mass is an important pre-condition for efficient biodegradation. There are 3 principal ways of solving this task:

- mechanical agitators,
- circulation of the fermentation mass by means of an outside pump,
- injection of biogas (mixing by the biogas bubbles moving upwards).

6.5.8 Desulphurisation of biogas

The most common and cost-effective solution for the desulphurisation of the biogas produced is the biological way when aerobic microbes convert H_2S into elementary sulphur in the presence of oxygen.

The biological desulphurisation can be carried out either in the biogas area on top of the digesters or in separate desulphurisation columns. The latter is a more efficient solution, which also causes limited dilution of the biogas with nitrogen (and oxygen) but requires additional investment costs. The biological desulphurisation solution can be extended with adding active-coal filters.

Different biogas upgrading technologies have different requirements towards the sulphur content of the raw biogas. For example, biomethane quality standards and natural gas grid requirements put strict limits on the oxygen content of the product. These requirements must be thoroughly considered at connecting the anaerobic digestion installation with the biogas upgrading facility. No decision can be taken on desulphurisation within the AD unit without knowing the specifics of the subsequent technological step.

6.6 Upgrading of biogas

Similarly, to the previous chapter on the anaerobic digestion, this section of the feasibility studies serves the information of addressees (mostly financial people) who may not have detailed knowledge of the technology to be applied in the project.

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Upgrading of biogas to biomethane means

- purification (removing components like water, hydrogen sulphide, ammonia, oxygen, nitrogen, carbon monoxide, halogenated hydrocarbons, siloxanes and particles)
  plus
- separation of carbon dioxide from methane.

Currently, biogas upgrading to biomethane is performed via water scrubbing, chemical scrubbing, physical scrubbing, pressure swing adsorption, and membrane separation. Recent advances have been made in the field of biochemical biogas upgrading using microbial-based systems and also in cryogenic upgrading. The cryogenic technology offers additional benefits, such as production of liquified biomethane (for transport fuel use) and the simultaneous production of high purity, food-grade carbon dioxide.

A comprehensive and up-to-date review of biogas upgrading technologies is provided in the Research review paper „Biogas upgrading and utilization: Status and perspectives" by Irini Angelidakia at all. in Biotechnology Advances.[6]

When selecting the upgrading technology several factors must be looked at, among them:

- expected composition of biogas (for example hydrogen sulphide, ammonia, oxygen, nitrogen content),
- the quality requirements – CEN-EN 16723,
- the natural gas grid technical requirements (for example pressure, oxygen content,
- the intended use (for example intermediary biomethane storage is needed if refuelling stations are supplied directly),
- parasitic load,
- the energy consumption (electricity and thermal) and the available energy sources,
- national regulations on limiting the methane emissions with the CO_2 stream,
- market options and requirements for selling the co-produced CO_2

The feasibility study should reflect that the upgrading technology has been carefully selected and the specific features of the chosen technologies have been taken into consideration when elaborating the material and energy balances.

In **The Example** no upgrading technology was identified, and no substantial thermal energy consumption was assumed. For purely illustration purposes 0,33 kWh/Nm^3 of biogas was considered for electricity consumption.

6.7 Storage of biogas

The biogas plants must have a buffer biogas storage capacity, while

- there are interruptions in the operation of the upgrading (and the CHP unit, if installed),
- the volume of biogas production is fluctuating in time.

[6] *journal homepage: www.elsevier.com/locate/biotechadv*

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Biogas can be stored in the gas domes [membranes] installed on top of the digesters. The other solution is the installation of stand-alone ¾ spheres. Both solutions are of equal technical value, the choice is mainly dependent on the configuration of the digesters.

The necessary minimum size of biogas storage capacity is to be determined considering the coupling with the upgrading unit. Installing big biogas storage capacity provides important operational flexibility but results in additional capital and operational costs.

6.8 Minimizing gas leakages

Due to the economic, safety and environmental significance of methane losses, biomethane plants need to be designed, planned, built, and operated considering the minimization of methane losses. There are several technical and organization measures to reduce the emissions from biomethane plants. Technical mitigation measures are real interventions on the plant, e.g., the installation of specific components and are mostly in connection with costs. Organizational measures describe the action sequences during plant operation. A non-exhaustive list of mitigation measures is listed below.

Technical mitigation measures:

- Gas-tight covering thanks, e.g., storing or mixing tanks
- Installing an exhaust gas treatment
- Correct dimensioning of biogas pipes
- Regular replacement of aged gas holder membranes

Organizational mitigation measures:

- Leakage tests before operation and instalment of regular leak detection thereafter
- Emission measurements after the renewal of plant components
- Gas holder filling level preferably at 50%
- Regular maintenance of openings
- Adjustment of substrate feeding regime before planned maintenance.
- Sufficient aeration during post-treatment
- Analysis of residual gas potential in the digestate

6.9 Material balances

The feasibility studies for biomethane investment projects must contain the estimated material balances of the processes foreseen. The respective data can and should be obtained from the technical offers of the respective technology suppliers. Only preliminary opinions can be formulated but no decisions should be made based on data from literature.

In case of converting an existing biogas plant to biomethane production the material balance of the anaerobic digestion unit will be composed from actual operational data.

The Tables below from **The Example** illustrate how the material balances can be provided in the feasibility study.

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For convenience of the readers, we repeat here Table 1. while this is the starting point for all calculations: needs to include grass silage and multispecies figures/yields.

	Volume	DM	oDM	Biogas	Biogas	Methane	Methane
	to/year	%	%	Nm³/to oDM	Nm³/year	%	Nm³/year
Cattle slurry	30.000	8,0	85,0	350,0	714.000	55,0%	392.700
Poultry manure	15.000	30,0	75,0	500,0	1.687.500	55,0%	928.125
Biowaste	5.000	30,0	85,0	550,0	701.250	52,0%	364.650
Maize stover	7.000	65,0	82,0	580,0	2.163.980	51,0%	1.103.630
Catch crops	10.000	27,0	92,0	620,0	1.540.080	53,0%	816.242
Maize/sorghum silage	15.000	32,0	93,0	650,0	2.901.600	52,0%	1.508.832
Recirculation	20.000	5,0	30,5				
Total/average	102.000	21,0			9.708.410	52,7%	5.114.179

In **The Example** (where the operation of local CHP is foreseen) the biogas balance could look like as given in Table 6.

Table 6: Biogas balance

	Nm³/year	Nm³/hour
Gross biogas production	9.708.410	1.214
Biogas loss (0,5%)	48.542	6
Biogas to CHP	1.880.537	235
Biogas for upgrading	7.779.331	972
Biogas methane content	52,7%	
Gross methane production	4.097.982	512

The DM (dry material) and oDM (organic dry material) balances are less important from economic point of view but they provide information on the level of conversion of organic material to biogas and on the expected DM content of the digestate coming out of the digesters. (Table 7.)

Table 7: DM and oDM balances

	DM input	oDM input	oDM input
	to/year	to/year	%
Cattle slurry	2.400,0	2.040,0	11,7
Poultry manure	4.500,0	3.375,0	19,4
Biowaste	1.500,0	1.275,0	7,3
Maize stover	4.550,0	3.731,0	21,5
Catch crops	2.700,0	2.484,0	14,3
Maize/sorghum silage	4.800,0	4.464,0	25,7
Recirculation	1.000,0		

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Total	**21.450,0**	**17.369,0**	**100,0**
Converted to biogas	12.067,6	12.067,6	
Remaining in digestate	9.382,4	5.301,4	
Fermentation residue (digestate)	**10,43%**	**30,5%**	

In anaerobic digestion facilities of this size the digestate is usually separated into two fractions, what makes the subsequent handling practical: the solid part can be transported for longer distances and marketed as fertiliser, while the spreading of the liquid fraction on cultivated land will be easier.

Table 8. illustrates the material balance of digestate separation under the assumptions of **The Example**.

Table 8: Seperation of digestate

Total volume	to/year	89.932
Assumed density	to/m^3	1,00
DM	%	10,43
Liquid fraction DM	%	5,00
Liquid fraction volume	m^3/year	65.505
Solid fraction DM	%	25,0
Solid fraction weight	to/year	24.427

The material balance of the upgrading unit must include the methane loss factor. This has double importance: on one side this reduces the volume of product gas, on the other hand any methane emitted to the atmosphere has a negative effect of the GHG emission intensity of producing biomethane. The methane loss factor is very much dependent on the selected upgrading technology and of its efficiency (for example of the number of stages in PSA or membrane separation). Table 9. illustrates the material balance of the upgrading stage under the assumptions of **The Example**.

Table 9: Material balance of upgrading

	Nm^3/year	Nm^3/hour
Biogas for upgrading	7.779.331	972
Gross methane production	4.097.982	512
Methane loss in upgrading (1%)	40.980	5
Net methane production	4.057.002	507
Carbon dioxide stream	3.640.369	455

6.10 Energy supplies

Both the anaerobic digestion and upgrading units consume electrical and thermal energy.

The level of energy consumption related to the biomethane production depends on

- the volumes and composition of substrates,

- the selection of technology (for example mesophilic or thermophilic digestion, membrane, chemical absorption, or any other upgrading technology),
- the energy demand of the necessary technological equipment,
- the energy consumption of digestate processing (for example drying).

Correspondingly, the feasibility study can address the issue of energy supplies only based on data available from the basic engineering of the AD and upgrading units.

The principal decision to be taken at early stage is the following: should the energy consumption of the installation be covered fully or mainly from own sources or – on the contrary – importing electricity and source(s) of thermal energy is preferred. It is important to note that the amount of subsidy for each Belgian project is calculated based on the net produced biomethane, excluding the energy needed to operate the installation.

The decision is very much dependent on the domestic regulations in respect to consuming fossil energy in renewable energy producing installations.

The straightforward solution for energy self-supply is to install a CHP (combined heat and power) unit burning biogas, generating electricity, and producing heat in form of hot water.

Pros for indigenous energy supply:

- the full volume of produced biomethane is qualified as renewable methane (while no fossil energy was consumed in the production processes),
- the regulations of applicable national financial support schemes may prohibit the consumption of fossil energy sources,
- the use of fossil fuel will be considered when calculating the operational support. Only the net produced renewable energy/biomethane is supported,
- self-supply protects from potential disruption of supplies from external sources,
- self-supply protects from potential future price increases for external sources (electricity, natural gas) and provides a stable basis for the cost projection of energy supply
- Self-supply eliminates the distribution costs of purchasing electricity or gas.

Cons for indigenous energy supply:

- for the security of operations, the connection to the electricity grid (as a back-up) is needed in any case.
- maintaining the process temperature in the digesters at times when the CHP is not in operation may require access to outside thermal energy source anyway.

Note: full independence from external energy sources cannot and should not be aimed at: the most sensitive part of the machinery and equipment must be operated, the process temperature in the digesters should be maintained also at times of disruption of the local CHP operation (for example for maintenance, etc,).

The easiest way of securing a back-up electricity supply is to establish a connection to the electricity grid with entitlement to take electricity any time. Alternatively, a local electricity generator could be installed, which would operate only in case of emergency.

The security of thermal energy supplies can be achieved in several ways:

- adding a boiler burning biogas to the machinery,

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- connecting to the natural gas grid and burning natural gas in a boiler,

In **The Example** the installation of one local CHP unit is foreseen and the electrical capacity of the CHP unit is determined by the estimated yearly consumption of electricity in the AD and upgrading units.

The co-generated thermal energy (usually available in form of hot water) can be used to cover the heat requirements of the digesters. In the Example no thermal energy consumption has been considered for the upgrading unit. Obviously, this approach is acceptable only for some of the upgrading technologies. In case of chemical absorption, the heat requirement is high, and this influences the thermal energy balances of the installation substantially.

In **The Example** three alternatives were considered:

- Alternative A: local CHP for self-supply of energy
- Alternative B: external energy supply through importing electricity and natural gas from the respective grids.
- Alternative C: external electricity supply, local biogas boiler for heating the digesters.

The basic data for the CHP unit are illustrated in Table 10.

Table 10: Basic data of the CHP unit

CHP data		
Electrical capacity	500	kW
Network connection	500	kW
Thermal energy production nominal capacity	540	kW
Conversion efficiency (to electricity)	40,5	%
Full load operating hours (calculated for 100%)	8.000	h/year

The estimated energy consumption of the AD unit:

Table 11: Estimated energy consumption of the AD unit

AD unit estimated energy consumption		
Thermal energy consumption	2.050.000	kWh/year
Electricity consumption	1.353.000	kWh/year
Loss of electricity, %	40.000	kWh/year

The thermal energy consumption of the AD unit fluctuates with the time of the year. Such fluctuations are illustrated in the Table 12.

Table 12: Thermal energy balance of the AD unit

	%	own consumption, kWh	thermal energy sold, kWh
January	12,5	256.250	230.000
February	10,5	215.250	180.000
March	10,0	205.000	160.000

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April	8,0	164.000	
May	6,5	133.250	
June	5,5	112.750	
July	5,0	102.500	
August	5,0	102.500	
September	6,5	133.250	
October	8,5	174.250	140.000
November	10,5	215.250	180.000
December	11,5	235.750	210.000
Total	**100,0**	**2.050.000**	**1.100.000**

Note: Table 13. includes an imaginary local utilisation of thermal energy for heating buildings in the cold months of the year.

Table 13: Thermal energy balance of the AD unit

Thermal energy balance	kWh/year	**%**
Thermal energy production	4.320.000	100,0%
AD unit own consumption	2.050.000	47,5%
Losses (5%)	216.000	5,0%
Thermal energy utilised	1.100.000	25,5%
Thermal energy not utilised	954.000	

Note: in **The Example** the thermal energy balance has been estimated without consumption by the upgrading unit (which is very much technology specific).

Alternative A with local CHP

The biogas balance in Alternative A:

Table 14: Biogas balance - Alternative A

	Nm^3/year	Nm^3/hour
Gross biogas production	9.708.410	1.214
Biogas loss (0,5%)	48.542	6
Biogas to CHP	1.880.537	235
Biogas for upgrading	7.779.331	972
Biogas methane content	52,7%	
Gross methane production	4.097.982	512

In **The Example** the electricity consumption of the upgrading unit in Alternative A is estimated as shown in Table 15.

Table 15: Electricity consumption of upgrading unit in Alternative A

Specific consumption	0,33	kWh/Nm^3 biogas
Biogas input	7.779.331	Nm^3 biogas input

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Electricity consumption	2.567.179	kWh/year

The electricity balance in Alternative A:

Table 16: Electricity balance in Alternative A

Electricity balance	kWh/year	**%**
Gross electricity production	4.000.000	100,00
AD unit consumption	1.353.000	33,83
Upgrading unit consumption	2.567.179	64,18
Loss of electricity, %	40.000	1,00
Net electricity production	39.821	1,00

Alternative B without local CHP and biogas boiler:

In Alternative B the necessary electrical energy and natural gas are imported, there is no CHP and no boiler consuming biogas. Correspondingly, the volume of biogas available for the upgrading unit is about 235 Nm^3/hour higher than in Alternative A. This increases the electricity consumption of the upgrading unit accordingly:

Table 17: Electricity consumption of upgrading unit in Alternative B.

Specific consumption	0,33	kWh/Nm^3 biogas
Biogas input	9.659.868	Nm^3 biogas input
Electricity consumption	3.187.756	kWh/year

The biogas balance in Alternative B:

Table 18: Biogas balance without local CHP and boiler

	Nm^3/year	Nm^3/hour
Gross biogas production	9.708.410	1.214
Biogas loss (0,5%)	48.542	6
Biogas to CHP and boiler	0	0
Biogas for upgrading	9.659.868	1.207
Biogas methane content	52,7%	
Gross methane production	5.088.608	636

Alternative C with local biogas boiler

In Alternative C part of the biogas is burned in boiler (to provide heating for the digesters), correspondingly the biogas volume available for the upgrading unit is lower.

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Table 19: Electricity consumption of upgrading unit in Alternative C

Specific consumption	0,33	kWh/Nm^3 biogas
Biogas input	9.226.169	Nm^3 biogas input
Electricity consumption	3.044.636	kWh/year

The biogas balance in Alternative C:

Table 20: Biogas balance in Alternative C

	Nm^3/year	Nm^3/hour
Gross biogas production	9.708.410	1.214
Biogas loss (0,5%)	48.542	6
Biogas to boiler	433.699	54
Biogas for upgrading	9.226.169	1.153
Biogas methane content	52,7%	
Gross methane production	4.860.145	608

Table 21. shows the comparison among the three alternatives:

Table 21: Feasibility indicators for energy supply alternatives

Alternative	A	B	C
Electricity	own CHP	imported	imported
Thermal energy	own CHP	Natural gas	Biogas boiler
Methane production, million m^3/year	4,10	4,86	5,09
IRR (12 years), %	10,02	9,37	17,32
NPV (10%, 12 years), EUR	1.298	-44.552	563.106

Under the assumptions applied in **The Example** importing electricity and natural gas would result in cost savings, but no conclusion should be drawn from this comparison, while energy supply prices and the regulations on consuming fossil energy in biomethane production can be substantially different from country to country (as illustrated by the graphs in this chapter). These three alternatives were shown here only to demonstrate how the feasibility study could approach such a question.

For further calculations in **The Example** Alternative A has been applied.

6.11 Conditioning, storage and delivery of products and by-products

6.11.1 Biomethane

The produced biomethane can be delivered to the market in several ways:

- injection into the natural gas network

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  - needed pressure, other technical, scheduling and reporting requirements are to be considered,
  - grid connections costs can differ substantially depending on volume, required pressure, distance, and required control equipment,
  - the feasibility study must include investment and operational cost data specific for the location.
- compressed in rail or road tanks,
- liquified in rail or road tanks.

Grid injection:

To feed the produced biomethane into the gas network, appropriate technical components, which can be designed differently depending on the individual case, must be available. The most important pieces of equipment include:

- connection pipeline,
- gas compression equipment
- intermediary gas storage
- gas pressure control, measuring and monitoring systems
  - Gas quality analysing and measuring system.
  - Odour injection equipment
- conditioning and gas mixing equipment (enrichment with propane)

In addition to the components for pressure control, quantity measurement and safety, further components are required, such as shut-off devices, filters and separators, thermometers, temperature sensors, manometers, pressure sensors, power supply data acquisition, data remote transmission, volume converters, and tariff devices.

For the planning, construction, equipment, and operation of a grid injection station for feeding biomethane into the natural gas network the applicable regulations and rules must be complied with. The costs of establishing the grid connection vary in a very broad range and for this reason in The Example no detailed investment budget for the grid injection was prepared.

The cost of pipeline for grid connection is a crucial item in the investment budget which may cause locating the biomethane production facility on a certain site unfeasible. The pipeline cost is a function of the distance between the plant and the gas network, the amount of biomethane produced and the complexity of the civil work requested (i.e., burial, crossing of rivers, motorways, railroads etc.).

In case the costs of constructing the pipeline connection and the grid injection station are prohibitive, the option of liquification or the delivery in compressed state could be considered.[7] Transportation via compressed composite trailer unit is a competitive alternative for transporting biomethane to central grid injection facility or to directly to off grid gas consumers.

[7] *Biomethane grid injection or biomethane liquefaction: A technical-economic analysis G. Pasini, A. Baccioli∗, L. Ferrari, M. Antonelli, S. Frigo, U. Desideri, Biomass and Bioenergy 127 (2019) 105263*

The quality of the produced biomethane must meet the relevant CEN-EN 16723 standard, which specify the quality parameters both for grid injection and usage as vehicle fuel.

6.11.2 Carbon dioxide

The impurities in the CO_2 rich stream, coming from the methane/carbon dioxide separation unit can be removed in the CO_2 recovery unit producing pure CO_2. The CO_2 recovery section includes a liquefying step and cryogenic unit(s) with a series of elements for the compression, drying and purification of the gas stream. The liquefaction and the thermal treatment allow a first separation between condensable pollutants and CO_2 on the one hand, and non-condensable gases on the other hand. Upon cooling to minus 30-33 °C, the CO_2 separates from the non-condensable gases (N_2, O_2, and CH_4). In an additional distillation and condensation step, the CO_2 reaches high chemical purity CO_2 (99.9+%). The non-condensable gases must be released to avoid their accumulation, but a fraction of this stream can be fed back to the membrane section to minimise gas losses.

To produce food grade quality, the CO_2 must meet the EIGA/ISBT standard of the European Industrial Gas Association and the International Society of Beverage Technologists. Correspondingly, the laboratory testing must prove that the product is completely bacteria and fungi-free, is odourless, tasteless, and colourless.

In the cash flow calculations of **The Example** the investment and operational costs of carbon dioxide production and the revenue from marketing are not included. Such an extension of the technology is to be addressed in a separate feasibility study in view of the market potential and quality requirements for carbon dioxide.

If to be marketed as a product, pure carbon dioxide will be stored and delivered in liquid form in tanks.

6.11.3 Digestate

The fermentation residue is a valuable by-product of the biogas process, while it contains – among others – phosphorus, potassium, and nitrogen (key components of mineral fertilisers).

In anaerobic digestion facilities of this size the digestate is usually separated into two fractions, what makes the subsequent handling practical: the solid part can be transported for longer distances and marketed as fertiliser, while the spreading of the liquid fraction on cultivated land will be easier.

In **The Example** it is assumed that the fermentation residue will be separated into solid and liquid fractions - for the purpose of easier handling and storage. Table 22 illustrates the digestate separation under the assumptions of **The Example**.

Table 22: Separation of digestate

Total volume	to/year	89.932
Assumed density	to/m^3	1,00
DM	%	10,43
Liquid fraction DM	%	5,00

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Liquid fraction volume	m^3/year	65.505
Solid fraction DM	%	25,0
Solid fraction weight	to/year	24.427

In **The Example** the dry matter distribution between the liquid and solid fractions were estimated as shown in Table 23.

Table 23: distribution of dry matter in the digestate fractions

Volume, to	DM	DM, to
89.932	10,43%	9.382
65.505	5,00%	3.275
24.427	25,00%	6.107

The fermentation residue (digestate) will be applied on the agricultural land cultivated by the local agricultural partners. What monetary value is being put on the solid and liquid fractions?

The solid fraction may have a market value as assumed in the financial feasibility chapter of this paper. The liquid fraction also contains valuable nutrients, so it is reasonable to expect that agricultural partners will be ready to take over the liquid fraction if the biogas/biomethane plant operator contributes to the transport costs.

6.12 Site selection

The site for the biogas/biomethane producing installation should be selected in the preplanning and pre-feasibility study phase considering several factors:

- what are the relevant local regulations on minimum necessary safety distances (explosion risk, odour exposure)?
- is the investment corresponding to the long-term development policies of the competent local authority (municipality, etc.)?
- are there long-term plans for road/rail/infrastructure constructions which impact the intended site?
- what are the technical conditions for connections to the electricity and gas grids for supplying energy to the biogas/biomethane installation?
- what are the technical conditions for injecting the produced biomethane into the natural gas grid (pipeline length and diameter, required pressure, etc.)?
- is the space required for the technology and for storing the substrates and the digestate (as specified in the technical offers by technology suppliers) available?
- is there a reserve space for possible future expansion?
- is the site connected to the public road?
- what are the distances for the land spreading of the digestate (first for bringing the liquid fraction to land cultivated in the vicinity)?

In course of the pre-feasibility study, in relation to the selection of the site, consultations with local key stakeholders including the local community and other parties (municipality, authority

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for building permits and public roads, archaeology, hydrology, ecology, flood risk assessment, traffic management, electricity grid operator, natural gas grid operator, fire-fighting body, farmers, agricultural companies) are necessary. Without selecting and securing the proper site for the project in the preparatory phase no meaningful feasibility study can be performed.

The site selection may be dependent on domestic situation, such as regulations. For the specific case of Flanders, the facility must for example be located at least 100 meters from a residential zone. Furthermore, a fence of at least 2 meters high should be present. In terms of implantation, Flemish regulation makes a further distinction between biomethane installations located in agricultural areas or in industrial zones. Installations in agricultural zones are bounded to extra spatial planning rules, limiting the origin of feedstock and the maximal capacity of the installations (Omzendbrief RO/2016/01). In Wallonia, the facility must be located at least 50 meters from a residential zone (AGW of 24/04/14). Implementation is allowed in both agricultural and industrial zones.

In general, the permitting authority will dictate measures to ensure a safe exploitation of the biomethane plant. Some of these measures will have a direct impact on the location of the site: emission values, road infrastructure, storage of explosive materials…

7 Market feasibility

7.1 Priorities in renewable energy policies

7.1.1 RED II

The RED II[8] is relevant to biomethane in several aspects:

- overall renewable energy target in final EU energy consumption,
- sectorial sub-targets: obligations on the renewable energy share in transport and heat sectors
- guarantees of origin to cover renewable gases,
- sustainability criteria for biogas

Biomethane can contribute to achieving the key RED II targets:

1. Member States shall collectively ensure that the share of energy from renewable sources in the Union's gross final consumption of energy in 2030 is at least 32 %.
2. The share of renewable sources in the transport fuel consumption should reach in 2030 at least 14%, including 3,5% from „advanced" fuels.
3. Each Member State shall endeavour to increase the share of renewable energy in the heating/cooling sector by an indicative 3.0 percentage points as an annual average calculated for the periods 2021 to 2025 and 2026 to 2030, starting from the share of renewable energy in that sector in 2020.

[8] *Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources.*

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The Union's 2030 renewables and energy efficiency targets have been expressed and agreed at EU level without underpinning binding targets at national levels. Instead, new working methods and new instruments have been established to enable the collective achievement of the objectives of the Energy Union. The EU Governance Regulation has created a unique system of energy and climate governance ensuring that the Union and its Member States can plan together and fulfil collectively these 2030 targets, as well as ensure a transition to a climate neutral economy that is fair and cost-effective for all. The RED II and the Governance Regulation[9] require Member States to establish 10-year integrated national energy and climate plans (further shortly NECP) for the period from 2021 to 2030.

The NECPs[10] specify the national contributions and the aggregated NECPs are sufficient for the collective achievement of the Union's 2030 targets set in 2018. With the European Green deal the European Commission took the commitment to put itself on track to become a climate neutral continent by 2050. To reach this ambitious goal the energy and climate objectives set by the Climate and Energy Package were no longer sufficient. For this reason, the entire climate and energy legislation underwent an extensive revision. A revised Renewable Energy Directive is currently being discussed by the co-legislators. The revision includes a higher Renewable energy target (40% in the Commission proposal), higher sectoral targets, a GHG savings target for the transport sector and stricter sustainability requirement for the biomass sector.

What will happen by 2030 will be largely determined by the national energy and climate plans. The NECPs play a key role in the EU's governance system to ensure that the member states join forces and deliver on the common objectives together. They should provide as much clarity and predictability as possible for the business and finance sector to stimulate necessary private investments. They will also facilitate Member States' programming of funding and investments in the next multi-annual financial framework 2021-2027. The governance process also provides an opportunity to update the plans in 2024 to reflect experience and to take advantage of new opportunities for the remainder of the decade.

The energy policy in Flanders is anchored in an overarching vision that lays down the most important development trajectories up to 2030: the Flemish Energy and Climate Plan 2021 – 2030 (FEKP 2030). The ambition in terms of biomethane production and consumption is very limited. The objective for biogas is to utilize the domestically available biomass flows in view of a shift to green heat. After all, the Flemish government wants to increase its focus on green heat production because the use of heat technologies is often more cost-efficient than green power or transport applications.

The vision of the FEKP 2030 was further elaborated in the Heat Plan 2025, which was published at the end of 2021. The Heat Plan 2025 puts forward 26 measures to make heat in Flanders more sustainable. The main measures for new biogas/biomethane projects were:

- New biogas installations should be built as much as possible at locations with sufficient heat demand.

[9] Regulation on the governance of the energy union and climate action (EU/2018/1999).
[10] https://ec.europa.eu/energy/en/topics/energy-strategy/national-energy-climate-plans

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- The useful application of heat from biogas CHPs is being examined. It will be investigated whether digestate drying can still be regarded as a useful heat application in new or strongly modified biogas CHPs.
- Support for biomethane production through the call or certificate support will be abolished.
- The support policy for biogas will take more into account the NOx and methane emissions and the influence of these emissions on the net environmental impact.

The vision of Wallonia is defined in the PWEC (Plan Wallon Energie Climat), published in 2019. The new version, which was supposed to arrive in 2021, is somewhat delayed. In the PWEC, the following relevant aspects are for example included:

- Renewable energy 23,5% of the gross final energy consumption in 2030
- Maintenance of a support system for green electricity
- Support for the production of green heat
- Use of renewables in transport
- Removal of administrative and regulatory barriers

More information can be found in Section 7.3.

7.1.2 The European Green Deal

As mentioned in the previous subchapter, The European Commission presented on December 11, 2019, the European Green Deal[11] aiming at delivering the EU political ambitious to shift the EU economy to climate-neutrality by 2050.

The 24-page proposal provides a roadmap setting legislation initiatives "*to boost the efficient use of resources by moving to a clean, circular economy and stop climate change, revert biodiversity loss and cut pollution*". It also outlines investments needed and financing tools available and explains how to ensure a just and inclusive transition.

The European Commission has presented exhaustive legislation proposals to revise all the energy, environment and climate legislative framework in the EU and put it up to speed to halt biodiversity loss, minimise air and water pollution and curb greenhouse gas emissions reaching a 55% saving by 2030. The so-called Fit-for-55 package includes:

Changes in the EU Emission Trading System

Each year, the EU ETS lowers the cap on emissions from particular economic sectors and sets the price for carbon dioxide emissions. The Commission suggests lowering the overall emission cap even more and quickening the pace at which emissions are being reduced each year. As for biomethane, this will be zero-rated under the system provided it complies with the Renewable Energy Directive rules.

[11] *Brussels, 11.12.2019 COM (2019) 640 final COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE EUROPEAN COUNCIL, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS*

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Effort Sharing Regulation
The regulation establishes stronger emission reduction goals for the building, road, and domestic maritime transportation, as well as the agricultural, waste management, and small industrial sectors, for each Member State. Considering the different starting points and capacities of individual Member States, these figures are based on their GDP per capita and are adjusted to take account of cost-effectiveness.

Renewable Energy Directive (see previous chapter)

Energy Efficiency Directive
The proposal requires Member States to reduce their energy consumption, with particular focus on building sector and heating.

Regulation setting new CO_2 emission standards for cars and vans
Commission proposal includes lower CO_2 emission standards for passenger cars and vans to accelerate the transition to zero-emission mobility by requiring a 55% reduction in average emissions from new cars. The regulation sets a ban on internal combustion engine for new vehicles from 2035.

LULUCF – Land use land use change and forestry regulation
The regulation proposal sets a EU target for carbon dioxide removal from natural sinks, corresponding to 310 million tonnes of CO2 emissions by 2030. By 2035, the EU should achieve climate neutrality in the land use, forestry and agriculture sectors, including other agricultural emissions.

Revision of the Energy Tax Directive
The revision of the Energy Tax Directive proposed aligning the taxation of energy products with EU energy and climate policies, promoting clean technologies and removing the outdated exemptions and reduced rates that now encourage the use of fossil fuels.

Revision of the Energy Performance of Buildings Directive
The Commission proposal on this directive sets out how Europe can achieve a zero-emission and fully decarbonised building stock by 2050. The proposed measures aim at increasing the rate of renovation, particularly for the worst-performing buildings in each Member State. It will modernize the building stock, making it more resilient and accessible.

Gas Decarbonisation Package
The European Commission proposal on the package aims to facilitate the integration of renewable and low-carbon gases into the existing gas network. It proposes inter alia to ensure that renewable and low carbon gases have access to the gas wholesale market abolish costs for cross-border tariffs facilitating trade and reduce injection costs for those gases by 75%.

7.1.3 REPowerEU

The geopolitical crises that lead to Russian's invasion of Ukraine, resulted in an extreme gas volatility. On Wednesday 18 May the European Commission published its plan setting out how the European Union can eliminate its dependency on Russian fossil fuels, called REPowerEU. As phase out of Russian coal imports has already been agreed and a gradual phase out of oil by end-2022 is currently under discussion, the REPowerEU plan focuses on how to phase out of Russian gas by 2027 in an orderly and affordable fashion. Notably, the REPowerEU includes a Biomethane Action Plan detailing tools and measures to scale up the sector and roll out 35 bcm of biomethane by 2030, including a Biomethane Industrial Partnership. The biomethane is among the ones prioritized by the European Commission in reaching a more sustainable and sovereign energy system. The Commission's action plan is structured along four main dimensions: 1) Energy Efficiency - Entailing a higher EE target and behavioral measures 2) Supply diversification – Common Purchasing of green hydrogen, LNG and gas from reliable trade partners 3) Energy transition acceleration – Higher Renewable Energy Ambitions reflected in stepped up targets 4) Investment and reforms – Revised Recovery and Resilience Plans, ad-hoc REPowerEU grants and calls under the main EU financing programmes. The European Commission reckons that delivering on the planned objectives will require an additional investment of €210 billion between 2022 and 2027. However, this would save almost €100 billion per year in reduced fossil-fuel imports.

The strategy includes a Biomethane Action Plan that aims at facilitating the increase in production of biogas and boost its subsequent conversion into bio-methane, respecting the criteria agreed in the REDII. The focus is on waste and residue-based capacity and on the development of sequential/cover crops and sustainable biomass in marginal land. The main weaknesses identified are lack of focus on transport and on cross border trading. The Plan's actions are grouped under 5 areas: (i) Promoting production, use and injection in the grid (ii) Providing Incentives for biogas upgrading into biomethane (iii) Promoting adaptation of existing infrastructure and the development of new infrastructure for biomethane through EU gas grid (iv) Address RND&I gaps (v) Access to finance. Higher renewable targets may drive biogas and biomethane demand. The Commission is proposing to increase the targets currently under discussion in the context of the Fitfor55 Package. Concerning transports, the advanced biofuels target is the only one remaining unchanged, while the increase of the Renewable Targets seems to be mainly covered by H2 and electrification.

7.2 Domestic market

The market feasibility very much depends on the prevailing domestic market conditions. The following issues determine the domestic market:

7.2.1 Support schemes

There are currently no support schemes anymore for biomethane producers in Flanders. Biomethane consumers also do not receive any support for the moment.

The Walloon government does provide operational support for biomethane producers, through LGOs (*Label de Garantie d'Origine*) and *'certificats verts'*. There can only be applied for this support if the biomethane is valorised in a fossil CHP-unit. For each MWh of biomethane, which is produced and injected into the natural gas grid, a LGO can be received. Biomethane installations can sell their LGOs to CHP-units located in the Walloon region, which operate on natural gas. In that way, CHP-units are greening their gas consumption and are producing green electricity and heat. This makes them eligible for a higher certificate subsidy rate than if natural gas is provided to the CHP, thus creating a financial incentive for the consumer.

7.2.2 Gas injection and distribution

7.2.2.1 G8/01 Regulation for decentralized gas injection

Quality requirements for biomethane injection are established on federal level in a technical regulation published by Synergrid. In addition to the injection standard, the technical regulation G8/01 specifies a number of procedures and rules to guarantee a safe injection of biomethane into the natural gas network. The basic requirement is that the injected gas must be of such a quality that all gas appliances or production processes connected to the grid work in a similar way as for natural gas, and this completely safe. The regulation only applies to injection into the transport and distribution network, and not to direct use in, for example, a CNG-filling station on site.

Any biomethane producer who wants to inject into the gas network is obliged to submit an application to the responsible network operator. The network operator first checks whether the existing gas network is suitable for injection. The planned injection flow rate must not exceed the local gas consumption. If the desired injection quantities are not completely possible for the given network, alternative solutions are connecting to a larger network or injection into the transport network.

In addition to the capacity of the grid, the quality of the injected biomethane is also important. The producer must always take the necessary measures to supply gas that meets the quality requirements. The network operator reserves the right to refuse the injection and to return the gas to the producer if it is not compatible. An overview of the composition and the characteristics that the biomethane must meet when injected into the distribution network can be found on the website of Synergrid.

The biomethane producer is responsible for the purification of the biogas to the required quality standard. The biomethane is sent to the injection cabin where the gas is odorized, and the quality is measured. If the biomethane is compliant, it is brought to the correct pressure and injected into the existing network. The injection cabin is operated by the network operator. The grid operator is responsible for the correct functioning of the cabin.

7.2.2.2 Technical Regulations for Gas Distribution

There are technical rules and regulations for the management, connection to and access to the natural gas distribution network and the basic closed distribution networks for natural gas. The regulations are set up by the VREG, the Flemish regulator for electricity and gas. The equivalent body for Wallonia is the Commission Wallonne pour l'Energie (CWaPE) which has the same functions.

Connection to the distribution network

For the connection of a biomethane installation to the gas distribution network, an application must be submitted to the natural gas distribution system operator (DSO). In the first place, the DSO must assess whether the installation can be safely connected to the existing gas network. A suitable connection point is determined by the DSO on the basis of technical and economic

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parameters such as the proposed hourly flow rate, the supply flow rate and the installation. Injection of biomethane is only allowed on medium pressure pipes of cat. b and c.

A detailed study is carried out by the DSO for every application. The following documents must be submitted in advance:

- a preliminary design of the implantation;
- a preliminary design of the buildings (if applicable);
- the principle diagram and the flow chart;
- the characteristics of the biomethane as a material;
- the safety data sheet of the biomethane;
- the production quantity and the profile of the injection flow rate.
- The final capacity

Once an access point is allocated, a connection contract is set up between the biomethane producer and the DSO. The following information must be provided:

- a list of planned devices and their specifications;
- a final version of the design plans (construction, piping, electrical and control systems);
- the technical specifications of the installation.

Injection cabin

The injection cabin is the property and responsibility of the DSO. In the injection cabin, the quality of the gas is measured and the gas is odorized. The DSO is the only one authorized to provide the installations for odorization and measurement of the quality of the gas. It is therefore the responsibility of the DSO to ensure the proper and safe operation of the connection. He is solely authorized to adapt, maintain, repair, replace, remove, decommission and operate the connection.

Biomethane producer responsibilities

The biomethane producer is obliged to exchange data with the DSO to ensure proper functioning of the injection. An annual report must be made of the maximum producible hourly flow, the estimated annual production, the description of the expected annual production profile and the technical data about the quality of the gas of the production installations in operation. The production units to be withdrawn from service must also be stated. The measurement data must be kept for five years and must be available at the request of the DSO.

Access to the gas network

The DSO has the right to terminate or suspend access to the network for a natural gas distribution network user, entirely or partly:

- on injection, if the odorant is not within the normal range;
- on injection, when off spec gas is being injected;
- on injection, when an impermissibly high pressure occurs in the receiving natural gas distribution network

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7.2.2.3 European standard for transport fuels from natural gas or biomethane (EN 16723-2)

There is not yet a separate quality regulation in **Belgium** for the use of biomethane as a transport fuel. There is referred to the European standard EN16723-2, which describes the quality requirements for transport fuels from natural gas or biomethane (Table 24), for guideline values.

Table 24: Conditions and limit values for biomethane as a transport fuel according to EN 16723-2

Parameter	Unit	Limit values[a]		Test method (informative)
		Min	Max	
Total volatile silicon (as Si)	mgSi/m³		0,3[b]	SP test method
Hydrogen	% mol/mol	-	2	EN ISO 6974-3 EN ISO 6974-6 EN ISO 6975
Hydrocarbon dew point temperature (from 0,1 to 7 MPa absolute pressure)	°C	-	−2 (as in EN 16726)	ISO 23874 ISO/TR 11150 ISO/TR 12148
Oxygen	% mol/mol	-	1	EN ISO 6974- series EN ISO 6975
Hydrogen sulfide + Carbonyl sulfide (as sulfur)	mg/m³	-	5 (as in EN 16726)	EN ISO 6326-1 EN ISO 6326-3 EN ISO 19739
S total (including odorization)	mgS/m³		30[c]	EN ISO 6326-5 EN ISO 19739
Methane Number	Index	65[d] (as in EN 16726)		Annex A of EN 16726:2015
Compressor oil			[e]	ISO 8573-2
Dust impurities			[e,f]	ISO 8573-4
Amine	mg/m³		10	VDI 2467 Blatt 2:1991-08

7.2.3 VLAREM/WALLEX

In Flanders, VLAREM is the implementation of the Flemish environmental permit decree. Activities are classified in three classes, class 1 being the most nuisance activities and class 3 being the least. Each class is linked to different (permit) regulations depending on the nuisance risk. Gases fall under section 16 of VLAREM II and a class is allocated depending, among other things, on the production capacity.

In Wallonia, the classes are similar. For biomethane projects, two sections are especially important in the context of an environmental permit or a *permis unique*. These are included in the Decree of the Walloon Government of 24 April 2014. It concerns section 40.40.10 for biomethane installations using biomaterials not constituting of waste and section 90.23.15 for installations using biomaterials constituting of waste. Class allocation depends, among other things, on the treatment capacity. More information can be foun in WALLEX, a database that provides access to the integral texts of the Walloon legislation.

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7.2.4 Sustainability criteria

7.2.4.1 Renewable Energy Directive (2018/2001) to promote the use of energy from renewable sources

Europe imposes sustainability and greenhouse gas emission reduction criteria for the use and production of biogas and biomethane. Depending on the physical phase (liquid or gaseous) and the end application (transport or other), different conditions apply. If biofuels, etc. do not meet the criteria, they are not eligible for financial support, their contribution is not considered for achieving the defined share of renewable energy per Member State (Art. 3 par. 1), and they cannot be used for compliance of any obligations regarding the use of renewable energy (Art. 25).

Since biomethane is used in both liquid and gaseous forms for various applications, the following definitions are important:

- biofuel: liquid fuel for transport produced from biomass;
- biomass fuel: gaseous or solid fuels produced from biomass;
- bioliquids: liquid fuel produced from biomass for energy purposes other than transport, including electricity, heating, and cooling.

If residues that do not originate from agriculture, aquaculture, fisheries, forestry or natural areas are used, the sustainability criteria do not have to be met. In addition, the greenhouse gas emission reduction criteria should not be followed when electricity, heating and cooling is produced from organic municipal solid waste.

If biomethane is used as a biofuel, all sustainability and greenhouse gas emission reduction criteria must be met. This means that it is checked whether the biomass is sustainable and does not come from valuable (natural) areas. The greenhouse gas emission reduction must be at least 65%.

7.2.4.2 Federal legislation

The implementation of the sustainability and greenhouse gas emission reduction criteria in federal legislation is not yet fully completed. The broad outlines are described in the European directive, but the actual implementation decree is laid down at the Flemish/Walloon level and can be stricter than what Europe submits. The obligations regarding biofuels are a federal competence and are therefore laid down by the federal government.

The following definitions are important for biomethane:

- gaseous biomass: a gaseous fuel for energy purposes other than transport, including electricity, heating and cooling, which is produced from biomass
- liquid biomass: a liquid fuel for energy purposes other than transport, including electricity, heating and cooling, which is produced from biomass
- biofuel: liquid fuel for transport produced from biomass

Solid or gaseous biomass produced from waste and residues that do not originate from agriculture, aquaculture, fisheries, forestry or nature reserves does not have to meet the sustainability criteria stated in this Decree.

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If biomethane is used as a biofuel, a product declaration must be set up with the FPS economy to verify the sustainability and the greenhouse gas emission reduction. If only residues not from agriculture are used, only a mandatory $CO_{2,eq.}$ reduction of 65% must be met.

Biofuels:
- each lot has a product statement that must include sustainability criteria and GHG emission reduction
- organic waste: only obligation 65% GHG emission reduction
- FPS recognizes European voluntary schemes

7.2.5 Registration system for biomethane

Once biomethane is injected into the gas network, it is physically indistinguishable from the 'fossil' or 'grey' gas molecules already present. A registration system is necessary to avoid double use and to guarantee the origin of the biomethane. Thanks to the registration system, the biomethane can be traced back to the end consumer based on GOs. A GO is a digital piece of evidence that proves the origin of biomethane. 1 GO is allocated per MWh of biomethane. The GO is not proof of the realized greenhouse gas emission reduction nor of the sustainability of the product.

The granting of GOs for biomethane takes place in two steps. The production registrar handles the application for granting GOs and registers and monitors the amount of biomethane produced by an installation. Fluxys has been appointed as production registrar in Flanders. The Flemish production coordinator, which is the VREG in Flanders, must monitor the correctness of the calculation principles for the number of GOs to be allocated and the way in which the production registrar transmits production data. The production coordinator then allocates GOs to the applicant based on those production data. In Wallonia, the DGO4 (la Direction Générale Opérationelle Aménagement du territoire, Logement et Energie) has decided to manage granting themselves.

The GOs represent the 'green' value of biomethane, in addition to the energy value of the gas. The GOs can be sold together with or separately from the physical gas supply. The average value of a GO biomethane was €20.43 in Flanders in 2021. There is currently no obligation within Flanders to state the origin of the consumed gas on the invoice.

The value of the LGO sold to a Walloon fossil cogeneration unit is closely linked to the selling price of the gas on the network. The sum of the gas price and its LGO is about 85€/MWh HHV (higher heating value). The lower the selling price of the gas on the network, the more the LGO will be worth. Note that this is a simplification of reality. More details on this mechanism can be found here.

7.2.5.1 Exchange with other Member States

It is currently not possible to trade GOs between different Member States or regions within **Belgium** via the VREG registration system. VREG is waiting for a European hub, as already exists for renewable electricity GOs, in order to guarantee a reliable exchange. The development of such a European registration system is precisely the aim of the REGATRACE project.

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7.2.5.2 Use of GOs within EU ETS

ETS companies can reduce their greenhouse gas emissions by using and purchasing renewable energy, including biomethane. GOs serve as evidence to show that the purchased energy was renewable. Both Flemish and foreign GOs can be used as long as a registration system for biomethane is in place in the country of origin. An additional condition is that the purchased biomethane is in line with the European sustainability conditions for the use of biomass as a biofuel. This is verified by a so-called voluntary scheme, recognized by the European Commission.

7.2.5.3 Registration system for biofuels

Suppliers of transport fuels in **Belgium** are obliged to reduce the greenhouse gas intensity of the supplied fuels by 6% compared to 2010. Biofuels, including biomethane, can be used to meet this target.

In order to use biomethane as a biofuel, a product declaration must be set up at the FPS Public Health, Food Chain Safety and Environment. With this declaration, the various product standards regarding sustainability, the origin and the CO_2-reduction of the biomethane are checked and guaranteed. A product declaration must be set up for each lot of renewable transport fuel.

Sustainability must again be demonstrated with a voluntary scheme, recognized by the European Commission. The calculation method for CO_2-reduction is established in Appendix 2 of the Royal Decree of 7 December 2021 (concerning the determination of product standards for transport fuels from renewable sources and for transport fuels based on recycled carbon) and follows the calculation rules of the RED II. The CO_2-reduction varies between more than 200% to less than 20% reduction, depending on the input flows and the installed technologies (Table 25).

Table 25: Typical and standard values for greenhouse gas emission reductions for biomethane for the use as biofuel.

Biomethane installation	Technological options	GHG emission reduction – typical value	GHG emission reduction – standard value
Manure	Open digestate, no flue gas combustion	117%	72%
	Open digestate, flue gas combustion	133%	94%
	Closed digestate, no flue gas combustion	190%	179%
	Closed digestate, flue gas combustion	206%	202%
Energy crops	Open digestate, no flue gas combustion	35%	17%
	Open digestate, flue gas combustion	51%	39%

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	Closed digestate, no flue gas combustion	52%	41%
	Closed digestate, flue gas combustion	68%	63%
Biowaste	Open digestate, no flue gas combustion	43%	20%
	Open digestate, flue gas combustion	59%	42%
	Closed digestate, no flue gas combustion	70%	58%
	Closed digestate, flue gas combustion	86%	80%

7.2.5.4 Voluntary schemes

Voluntary schemes, recognized by the European Commission, have been established to monitor the sustainability criteria of biofuels. Monitoring the sustainable use of biomass flows is gaining importance and is now also mandatory for other forms of bioenergy.

The sustainability certificates, issued by a voluntary scheme, are traded and used in several Member States to meet certain sustainability objectives such as the blending of biofuels. In 2022, the willingness to pay for a sustainability certificate is higher than for a GO, precisely because biomethane with a sustainability certificate can be used for greening transport fuels.

7.2.6 Use of biomethane

In 2020, there were 134 biogas plants in Flanders and 55 in Wallonia. In addition to the classic valorization of biogas by a (local) CHP-unit to heat and electricity, the first biomethane was injected in the gas grid in 2018. At the end of 2021, Belgium counted five biomethane installations, two in Flanders and three in Wallonia.

Bio-CNG is produced in **Belgium** (Wallonia) since 2021. The first Flemish bio-CNG production, in this case from OMSW, is in the pipeline. Some CNG-filling stations provide a blend of CNG and imported bio-CNG. Note that for the specific case of Flanders, the government is favoring electrification of passenger transport. Bio-LNG from Belgian biomethane is not yet produced up till now. However, the possibilities for onsite production are investigated. Besides, Fluxys has a liquefaction installation in the terminal of Zeebrugge, which they use to produce bio-LNG based on biomethane injected in e.g., Germany.

For more information on the possible use of biomethane for heating purposes, see Subsection 7.1.1. Interest of domestic industries for procuring biomethane depends on the existence of a competitive advantage. At the moment, no specific projects are ongoing in that context.

7.3 Export market possibilities

In principle there are several ways of exporting biomethane into another European country:

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a) **Direct physical deliveries in tanks compressed or liquified (road, rail, water)** – the administration is the same as for liquid biofuels.

b) **Physical deliveries in natural gas pipelines** – following the rules and procedures of natural gas transport/transit.

c) **Virtual transfer of „renewable" value by means of Guarantees of Origin (GOs) –** regulated in RED II

d) **Mass-balancing in the natural gas network –** the ERGaR concept of cross-border biomethane administration

a) Direct physical deliveries in tanks are available only in limited geographical circle around the biomethane production installation, and in limited volumes. This way of bringing biomethane to the market is very specific to local circumstances. Nevertheless, if demand over the border arises, the feasibility study can be performed reflecting the concrete situation for volumes, forms of delivery and pricing.

b) The physical deliveries through natural gas pipelines can be realised in accordance with the natural gas transport administration, following the rules and procedures which are valid for forwarding natural gas cross-border transfers (the transport/transit capacities must be booked, delivery schedules must be strictly met, etc.). Such deliveries are arranged today in practice, although the volumes are quite small yet. The burdensome and costly administration makes economic sense only if the biomethane imported is qualified for state aid/financial benefits. The ruling of the European Court of Justice in Case C-549/15 at the European Court of Justice (ECJ) E.ON Sweden vs. Swedish Energy Agency provides the legal basis for these transactions. The ECJ judgement confirmed that sustainable biomethane could be forwarded cross-border through the interconnected European natural gas pipeline network subject to proper mass-balancing administration and sustainability verification.

c) Guarantees of Origin issued for biomethane consignments can be exported under the condition that the related methane volumes have not been placed on the domestic market as renewable gas. The RED II extended the system of Guarantees of Origin (further GO) to renewable gases in the expectation that this will create a European market for such gases, among them biomethane. As per definition the value of the GOs is determined by the customers willing to pay a premium (over natural gas) on a voluntary basis.

Respective quotes from RED:

"Guarantees of origin which are currently in place for renewable electricity should be extended to cover renewable gas. … This would provide a consistent means of proving to final customers the origin of renewable gas such as biomethane and would facilitate greater cross-border trade in such gas. It would also enable the creation of guarantees of origin for other renewable gas such as hydrogen."

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"Guarantees of origin issued for the purposes of this Directive have the sole function of showing to a final customer that a given share or quantity of energy was produced from renewable sources."

"A guarantee of origin can be transferred, independently of the energy to which it relates, from one holder to another."

The information on financial support received is included on the list of obligatory content of GOs. This means that the RED II explicitly allows for issuing GOs for subsidised biomethane volumes. Nevertheless, the Member States are also entitled not to do so:
"Member States shall ensure that a guarantee of origin is issued in response to a request from a producer of energy from renewable sources, unless Member States decide, for the purposes of accounting for the market value of the guarantee of origin, not to issue such a guarantee of origin to a producer that receives financial support from a support scheme."
This right of the Member States must be taken into consideration when planning the sale of GOs for supported biomethane volumes. In any case, exporting GOs may provide an additional income for biomethane producers and – correspondingly – the possibilities for exporting GOs should be addressed in the feasibility studies. Nevertheless, it is very difficult to forecast the future income from selling GOs as long as no European forward market for these certificates is available for securing future prices.

Estimating future income from exporting GOs is challenging and calls for cautious approach. The declared function of GOs is informing the final consumers about the renewable origin of the energy carrier. It cannot be expected that the voluntary readiness of final consumers to pay for the green value in the future will provide the foundation for financing investments today – if no mature GO forward market is established, which would enable fixing future GO income for medium-long term.
The GOs cannot have an investment activity fostering impact also on economic considerations, per definition these GOs will always have a limited market value:

- the value will be determined (independently from the production costs) by the final consumers, who ***voluntarily*** decide on buying these GOs for demonstrating their environment/climate friendly attitude.
- the GO imports do not qualify for state financial support and for accounting towards national renewable energy commitments of the importing country.

d) Mass-balancing in the natural gas network - the ERGaR concept for administration of cross-border biomethane transactions

The main purpose of the European Renewable Gas Registry (ERGaR) association is to establish an independent, transparent, and trustworthy documentation scheme for mass balancing of biomethane distributed along the European natural gas system. In essence, ERGaR is to be seen as a network of national biomethane registries. Building on the activities of the national registries the common European documentation system enables cross-border trade of renewable gases via the European natural gas network while preventing double sale and double counting. The ERGaR administration is following the mass balancing methodology on a consignment-by-consignment basis.

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In accordance with ERGaR's cross-border biomethane administration concept, the cooperation among the national biomethane registries issuing the biomethane Proofs of Origin has a central role in the transfer and mass-balancing of biomethane consignments along the European natural gas network.

It is to be noted that the ERGaR mass-balancing administration is different from the volume (energy) balancing processes of the network operators in the natural gas industry. The balancing in the gas industry is related only to balancing volumes in transportation, while the mass-balancing for biomethane must also cover tracking the sustainable and renewable ("green", "bio") quality from production through injection until withdrawal and usage of the product.

The balancing in the gas industry begins with the injection and does not cover the origin and the production of biomethane. So, the balancing in the gas industry is aimed at

- establishing physical equilibrium between the injected and taken-out volumes and
- enabling security of supply to all end users and
- balancing any outages or oversupplies within the respective gas balancing areas in each country.

The physical balancing in the natural gas transportation and distribution systems has a continuous character; the equilibrium must be achieved at every moment. On the other hand, in case of biomethane the equilibrium between the injected and withdrawn volumes (expressed in energy units) is to be established within a set time frame.

7.4 Competition for substrates and products

7.4.1 Competition for substrates

Biomethane project developers must be aware that some of the raw materials they are planning to process may have a competing usage which impacts both the availability and costs of the supplies to the anaerobic digestion unit. This competition is mainly in the field of animal feed/fodder and of the production of liquid biofuels. Nevertheless, the substrate demand of other biogas installations in the area may also put limitations on the raw material supply to the project under preparation.

- Animal slurry

Solid manure (mostly with straw as bedding material) has been used as fertiliser and soil improver in the agriculture for centuries. In view of the accumulated experience, farmers are still interested to apply it on the fields, so it would be misleading to believe that solid manure is available for the biogas plants for free. Among the operational costs the price to be paid to the animal farmers must be considered. Alternatively, a solid manure – solid faction of digestate exchange can be negotiated with the farmers, what would be a mutually beneficial and stable solution.

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The situation with liquid manure (often called slurry) is different. Spreading slurry on the cultivated land is broadly practiced but has to be phased out for GHG emission considerations. The anaerobic digestion is providing the most efficient solution for the treatment of slurries and the biogas/biomethane project is not exposed to competition by other usage.

- Biodegradable organic waste

Certain bio-waste streams, mainly from beverage and food processing, have a competing application, they can be also used as fodder (or component to fodder). If these materials (for example: spent grains from ethanol production, rape-seed press cake from biodiesel production, sugar-beet press cake etc.) find place on the animal feed market, the income is substantially higher than the value generated through anaerobic digestion.

The landfilling of biodegradable organic materials from households must be forbidden. The bulk of the separately collected bio-waste from households is currently still treated in composting plants. Due to the EU new waste legislation and developments in the biogas sector, an increasing amount of bio-waste material from this category can be expected for digestion.

The new waste legislation is clearly promoting the source separated collection of biowaste and treats anaerobic digestion as the preferred method of recycling. The recycling targets combined with strict limitations on landfilling create serious challenges in those countries, regions and communities which still landfill the bulk of the municipal waste. The municipalities in Europe are expected to take strong measures towards source separated collection and recycling. Processing the biodegradable organic waste materials with high water content for biomethane as the target product will have no real competition in the future.

- Crop residues

Crop residues are parts of the crop that are not harvested during standard agricultural operations. Significant amounts of agricultural residues remain on the field after harvest. The utilisation of these residues (also called by-products from agriculture) depends on a number of factors, such as types of crops, crop rotation, crop mix, agricultural practices, harvesting technics. There are considerable differences in Europe regarding cultivated area, types of crops and yields due to climate and soil conditions, accessibility and farm practices.

Straws from cereal, maize and rapeseed production are the main crop residues, which are already used for several different purposes. The majority of the available (cereal based) straw is used for animal housing. Straw can be collected for combined heat and power installations (CHPs), wheat straw is already used for bioethanol production, other biomass-to-liquid technologies are under development. The domestic market situation for wheat straw is to be analysed to see whether this material is available for the biogas plants at all and – if yes – whether the costs are acceptable.

Substantial part of straw remains on the field for keeping soil fertility. In view of its characteristics maize straw is much more suitable for anaerobic digestion than wheat straw and has fewer competing usages – for these reasons among crop residues maize straw is the

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most prospective resource for the biogas/biomethane industry. Nevertheless, the biogas/biomethane project must be ready to cover the costs of collecting, transporting, conserving, and storing maize straw.

There are many other primary residues that can supply biomass for bioenergy such as multispecies/grass silage of permanent grasslands (this material is usually used for hay or silage production and is subsequently applied in animal husbandry), grass silage [Cuttings] could also originate from parks or other recreational areas, nature conservation areas and abandoned grasslands. In these cases, no competing use is to be considered but the costs of collection, transportation and storage must be covered.

- Catch crops/cover crops/second crops.

Catch crops (cover crops, second crops) are cultivated on the same piece of arable land before or after the main crops. These crops are mostly used to bridge the time in between main crop cultivations when the area would otherwise just consist of delicate fallow land. In this context catch crops/cover crops help to prevent water and wind erosion, nutrient leakage and consequently soil deterioration.

Multispecies pasture to be considered as rotation crops, due to increased productivity of 17tDM.ha, and up to 70% reduction in nitrogen requirements.

7.4.2 Competition for the products

- Biomethane

The consumers of biomethane are the same as the consumers of natural gas. It is important to recognise that the natural gas prices are different in different segments and if biomethane is supplied directly to the end users the wholesale costs can be substantially reduced.

FEBEG, the Federation of Belgian Electricity and Gas companies, demonstrates via their statistics that the natural gas consumption amounted to 190 TWh for Belgium in 2021. This number is comparable to the one in 2019 and 2020. The 102 TWh linked to the distribution network (natural gas consumption of individuals and SME's) is higher than previous years, due to lower temperatures in 2021. Natural gas for Belgium is predominantly imported from Norway and The Netherlands.

The CREG, the Commission for the Regulation of Electricity and Gas in Belgium, publishes every semester an analysis of the natural gas prices in Belgium. An increase from about 90 to 130 euro per MWh can be observed for Belgian households from December 2021 to June 2022. For SME's, this is an increase from about 70 to 130 euro per MWh. The general increase is in line with the average trend in other European countries. As the CREG states, it can be explained on the one hand by the resumption of economic activity after the sharp decrease in demand caused by the COVID-19 crisis in 2020 and on the other hand by the war in Ukraine and geopolitical tensions worldwide.

For biomethane designated as transport fuel the competition is from liquid biofuels, while both liquid and gaseous renewable fuels are counted towards meeting the biofuel/advanced biofuel

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quota targets. In this field the competition for biomethane is very direct: the marketing of biomethane must be financially attractive to fuel suppliers in comparison with meeting their commitments with liquid biofuels. In several European countries the biofuel/advanced biofuel quota obligations can be fulfilled by certificates issued for biomethane consignments supplied for transport. One example is the system of RTFO-RTFC in United Kingdom, another example is the GHG emission reduction commitment of transport fuel suppliers in Germany. In both cases non-fulfilment is penalised, and the amount of penalty is the ceiling for the prices of biofuel certificates.

- Carbon dioxide

Examples of direct CO_2 utilization in the chemical industry are enhanced oil recovery (EOR) and enhanced coal-bed methane (ECBM) recovery. In the pharmaceutical and medical fields, CO_2 is used in a mixture with oxygen/air to promote deep breathing or for surgical dilation by means of intra-abdominal insufflations. Among the different CCU techniques, the use of CO_2 in the food market represents a relatively small but significant storage capacity and a moderate lifetime of storage. Its main use is in packaging, as preservative agent that increases the food shelf-life or for the carbonation of soft drinks, mineral water, and beer.

The fossil CO_2 supply chain is mostly based on fossil fuel combustion (carbon, natural gas, fuel oil, etc.); on gasification of solid fuels (carbon, oil shale, etc.); on extraction of CO_2 from geological reservoirs; and on CO_2 separation from petrochemical and chemical processes (such as syngas).[12]

Before taking a decision for additional investments resulting in production of (preferable food-grade) carbon dioxide the demand-supply situation on the domestic market must be carefully studied and considered. For example, the price of natural gas is a driver for ammonia producers to stop or relocate their production. As the natural gas price is currently high, this might jeopardize CO_2-sourcing. Biomethane installations can offer a solution there.

- Digestate

Digestate can in the most part replace mineral fertilisers, but this is not a direct market competition situation. The value of digestate bio fertiliser can be calculated similarly to mineral fertilisers, i.e., based on the nutrient content, but the comparison is always local depending on the location of the biogas/biomethane plant and its integration into the agricultural environment.

In Flanders, digestate products originating from (co-)digestion of animal manure (with crop residues) is assigned the status of 'animal manure'. The fertilization standard of maximum 170 kg of nitrogen (N) per hectare per year from animal manure should not be exceeded. Due to the imposed limitation on the application of N from animal manure, the allowed application of

[12] *Simultaneous production of biomethane and food grade CO2 from biogas: an industrial case study by Elisa Esposito, Loredana Dellamuzia, Ugo Moretti, Alessio Fuoco, Lidietta Giorno and Johannes C. Jansen Energy Environmental Science. 2019, 12, 281*

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N from animal manure is lower than the crop N demand. To fill the gap, synthetic N fertilizers are used by farmers. In Flanders, more than 50% of the digestate is exported. In Wallonia, it mainly concerns local application as less digestate is produced than the available space for it on the fields. Export of digestate from Flanders to Wallonia is not forbidden. However, spreading that digestate on Walloon fields is.

Based on the results of the SAFEMANURE study, criteria were established in 2020 for recovered fertilizers from animal manure to act as an artificial fertilizer substitute. If those criteria are met, such products are categorised as RENURE (= REcovered Nitrogen from manURE). In the future, these products could get an exemption to the Nitrates Directive, provided that the same provisions laid down in the Directive are followed as for nitrogen fertilizers.

In regions like Flanders, with a strong livestock sector and related animal manure surplus, recognition of RENURE-products can on the one hand be an important step towards circular agriculture and, on the other hand, provide CO_2 and cost savings through a decrease in artificial fertilizer use. Mineral concentrates and ammonium salts, obtained after extensive treatment of animal manure or digestate via, for example, membrane filtration or stripping-scrubbing, appear to have the best chance of being recognized. Although several pioneers are already producing these products in Flanders, the criteria have not yet been included in Flemish policy. RENURE-products can therefore not yet be used as such. The use of artificial fertilizers remains necessary and represents a significant chunk out the budget, especially now that artificial fertilizer prices are higher than ever.

8 Commercial feasibility

8.1 Biomethane revenues

8.1.1 Revenue sources

The revenues of the biomethane producer related to the sale of the primary product (biomethane) may consist of several components:

- sales price of the molecules (corresponding to the prevailing prices on the market segment where the physical product is being delivered),
- feed-in-premium (FIP) from a financial support scheme of the national government, if any,
- price premium paid voluntarily by the customer in respect of the „green" value (environment friendly, renewable, sustainable, etc.) of the product, if any,
- price premium paid by the customer in respect of the tax benefits the consumer is granted for purchasing renewable gas,
- income from the sale of Guarantees of Origin, if any,
- income from the sale of biofuel certificates, if any,
- income from the sale of ETS certificates, if any.

All these revenue components are subject to the conditions and regulations of the domestic market and no guidance can be given on European level on estimating, calculating these revenues. For this reason, the present General Guidance does not provide any details which would be valid all over Europe. Nevertheless, it is underlined that in the feasibility study performed for the given biomethane project all these potential income items must be addressed, even if not available now.

The state aid in form of Feed-in-Tariff (FIT) is a special case: national governments supporting the domestic biomethane production in this way may put restrictions on the biomethane producer acquiring any other revenue in relation to the product in addition to the FIT. For example, the government may regulate that the subsidised biomethane must be brought to the market via a government designated company/organisation (i.e., DSO) and the producer is not entitled to market the product freely. Similarly, governments may rule that no Guarantee of Origin will be issued for FIT subsidised biomethane consignments.

In view of the variety of revenue sources in **The Example** we do not start the cash flow calculation from a biomethane sales price estimate. Instead, we apply the term about „biomethane total sales revenue" which includes all above listed (and potentially other available) elements. In **The Example** the calculations are performed with a reverse approach: instead of calculating feasibility indicators for a given sales price we calculate the „total sales revenue" necessary for achieving the targeted feasibility indicators.

In the base case of **The Example** the required biomethane sales revenue in 6,05 EUR/Nm^{3}.

For avoidance of different interpretations: any potential „gate fee" type income, received for taking over specific waste streams are not considered as part of „total sales revenue". This income, if any, should be considered at calculating the total costs of substrate supplies (as an element decreasing these costs). Similarly, any income from the sale of by-products (digestate, carbon dioxide, electrical and thermal energy) must be considered as separate revenue sources and not as part of the sales revenues related to the primary product itself.

8.1.2 Support schemes

The summary on support systems with country specific data is provided in REGATRACE Deliverable 6.1. „Mapping the state of play of renewable gases in Europe" (www.regatrace.eu):[13]

Feed-in Tariff (FiT) = A Feed-in tariff is a technology-specific support scheme providing a technology-specific remuneration per unit of renewable energy. Public authorities define and guarantee the tariff for a specific time period. Typical advantages are:

- Long-term contract with producer (often 10 -20 years)

[13] *Further information on support systems is available:*

a) *Horschig at all. „Biogas Upgrading: A Review of National Biomethane Strategies and Support Policies in Selected Countries" published 2019, Licensee: MDPI Basel, Switzerland*
b) *Banja at all. „Renewables in the EU: an overview of support schemes and measures" JRC report JRC110415, published 2017*
c) *Renewable energy policy database and support www.res-legal.eu*

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- Guaranteed grid access
- Payment levels based on the renewable energy generation costs.

Feed-in premium (FiP) = A Feed-in premium is a bonus to be paid above the prevailing, pre-specified benchmark market price. It is a technology-specific subsidy level per unit of renewable energy at a pre-set, fixed, or floating rate. The premium can be designed to estimate the avoided externalities of renewable energy generation, or to cover energy generation cost by the total payment. The two typical FiP designs are either a constant (fixed and predetermined) price or so-called sliding price allowing variations of the premium as a function of the prevailing price.

Quota/green certificates scheme (GC) = In a quota/GC system, the production of renewable energy is encouraged by an obligatory target stating a specific share of renewable energy in the mix of producers, consumers, or distributors. Often compliance is tracked by the trade of renewable energy certificates, which provide an additional supplementary revenue to electricity sales. Renewable energy generators benefit by selling their energy to the grid at market price and by selling certificates on the green certificates market.

Fiscal incentives = Tax exemptions or reductions are usually additional (and minor) support systems. Renewable energy generators receive certain tax exemptions (e.g., carbon taxes) as compensation for the competitiveness of the renewable energy market and its development. The impact of fiscal incentives is dependent on the applicable tax rate.

Investment support = An investment support is a fixed amount received before, during or shortly after the building phase of the plant. It is independent of the amount of renewable energy production.

8.1.3 Biofuel certificates

Some governments impose mandatory biofuel quotas or GHG emission reduction commitments on transport fuel suppliers. Such commitments can be met either by producing/purchasing/marketing physical biofuel volumes or by purchasing biofuel (or GHG emission reduction) certificates. The costs of these certificates are included in the fuel prices paid by the final consumers (by the motorists) and not by the state. For this reason, this is not a direct state aid to the producers but still a very important driver for producing and marketing biomethane.

It is to be noted that in the biofuel certificate systems, biomethane is usually just one of the biofuels and is competing with the liquid biofuels on the certificate market. Because of a minor share of biomethane on the total biofuel market the biomethane specific supply/demand patterns have very limited impact on the biofuel certificate price movements. (*Italy is a special case, where the government introduced a biomethane specific scheme).*

The new biofuel shares targets fixed in RED II will likely add to the future demand for biofuel certificates, including those issued for biomethane consignments.

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It is to be remembered that the fuels qualified as „advanced" in accordance with Annex IX. Part A of the RED II are counted double towards the targets and correspondingly get two certificates.

Some of the biofuel certificates are already traded internationally but the European market is not mature enough to make reliable price forecasts for the exported certificates.

In Germany the regulation promoting the use of biofuels was changed in 2015, the GHG reduction commitment replaced the biofuel volume quota commitment. For 2020 the min. GHG emission reduction level is set at 6%. Non-performing fuel suppliers must pay a penalty of 470 EUR/to CO_2 eq. GHG reduction, the penalty determines the theoretical upper limit for the market price of the GHG emission certificates. It is possible that other European governments follow this example and focus on GHG emission reduction effect rather than on physical volume shares. Due to the negative GHG emission intensity biomethane produced from manure enjoys clear benefits under such a system.

In the Netherlands, according to the Energy for Transport compliance system transport fuel suppliers can meet their annual obligation through purchasing renewable energy units (HBEs: *hernieuwbare brandstofeenheden*).

In the United Kingdom the Renewable Transport Fuel Obligations (RTFO) can be fulfilled by acquiring Renewable Transport Fuel Certificates (RTFC).

8.1.4 Guarantees of Origin (GOs)

Respective quotes from the RED II:

"Guarantees of origin which are currently in place for renewable electricity should be extended to cover renewable gas. This would provide a consistent means of proving to final customers the origin of renewable gas such as biomethane and would facilitate greater cross-border trade in such gas. It would also enable the creation of guarantees of origin for other renewable gas such as hydrogen."

"Member States shall ensure that a guarantee of origin is issued in response to a request from a producer of energy from renewable sources, unless Member States decide, for the purposes of accounting for the market value of the guarantee of origin, not to issue such a guarantee of origin to a producer that receives financial support from a support scheme".

"Guarantees of origin issued for the purposes of this Directive have the sole function of showing to a final customer that a given share or quantity of energy was produced from renewable sources."

"A guarantee of origin can be transferred, independently of the energy to which it relates, from one holder to another."

"Member States or the designated competent bodies shall put in place appropriate mechanisms to ensure that guarantees of origin are issued, transferred and cancelled electronically and are accurate, reliable and fraud-resistant."

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The RED II extended the system of Guarantees of Origin to renewable gases in the expectation that this will create a strong European market for such gases, among them biomethane. Per definition the value of the GOs is dependent on the willingness of the final customers to paying a premium (over natural gas) on a voluntary basis. This implies that in case of a GO price increase the demand for GOs is likely to decrease or diminish. By other words: the GO market will mostly be a buyer's and very rarely (if ever) a seller's market – a shortage of offer will not result in price increase (like it is usual with other commodities), For these reasons the forecast for future income from the sale of GOs must be conservative.

To establish the envisaged European market of renewable gas GOs will be difficult and time-consuming. The main obstacle is that different support systems and different export/import limitations are in force in different countries and in most cases the imported biomethane is not treated equally with the domestic production.

8.2 Other income streams projection

- Commercialisation of production and sale of digestate as by-product
- Commercialisation of production and sale of carbon dioxide as by-product
- sale of surplus electrical and thermal energy

8.2.1 Fermentation residue

In view of the high volumes of fermentation residue (digestate) its disposal/utilisation requires careful attention in the preparation of feasibility studies. Although the digestate contains valuable nutrients, its placement may turn out to be very problematic and – under certain conditions – the fermentation residue will cause more costs than income. In **The Example** it was assumed that the digestate is separated into solid and liquid fractions (to facilitate better placement and distribution).

Table 26: Digestate fractions in The Example

	to/year	DM %	DM to/year
Fermentation residue total	89.932	10,43	9.382
Liquid fraction	65.505	5,00	3.275
Solid fraction	24.427	25,00	6.107

Table 27: Estimated nutrient content of solid fraction in The Example

Estimated nutrient content	**kg/to**	**kg/year**	**value, EUR/kg**
Nitrogen total	5,80	141.679	0,600
Phosphorus (P_2O_5)	5,00	122.137	0,500
Potassium (K_2O)	5,80	141.679	0,500
Total/average	**16,60**	**405.496**	**0,535**

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The nutrient content data can be taken – for example – using the calculation model provided: https://www.lfl.bayern.de/iab/duengung/031516/index.php.

Table 28: Assumption of market value of digestate solid fraction

Nutrients average market value	EUR/kg	0,535
Value of nutrients in solid fraction	EUR/year	216.915,7
Discount for non-standard quality	%	40,0
Market value as discounted	EUR/year	130.149,4
Solid fermentation residue DM	%	25,0
Solid fermentation residue volume	to/year	24.427,4
Solid fermentation residue value	**EUR/to**	**5,3**

8.2.2 Sale of surplus thermal energy

In **The Example** the cash flow calculations were performed under the assumption that part of the biogas is burned in a local CHP unit to secure electrical and thermal energies for the operation from renewable source. It was also assumed that part of the thermal energy not used for heating the digestate can be utilised in cold months for heating buildings. The value of so utilised thermal energy in included in the revenues of the plant at 0,03 EUR/kWh.

Table 27. shows the composition of revenues in **The Example** (at full capacity):

Table 29: Composition of revenues in The Example

Income source	EUR/year	%	Price	
Biomethane sales revenue	2.447.123	93,75	0,0605	EUR/kWh
Thermal energy local utilisation	33.000	1,26	0,03	EUR/kWh
Digestate soled fraction	130.149	4,99	5,3	EUR/to
Total income	2.610.272	100,00		

8.3 Investment costs

The investment costs for a biogas unit are greatly influenced by the local conditions, among them the following non-technological factors may have a substantial impact:

- Availability of storage facilities for raw materials and fermentation residue, resp. the necessity of constructing new storage capacities for these purposes,
- Conditions for establishing both the electricity and natural gas network connections (voltage, pressure, distance, etc.)
- Magnitude of costs of earth works, road construction, etc.
- Logistics for substrate supplies and digestate placement.

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No final feasibility study should be produced without having the site of the installation identified. The impact of site selection can be quantified in the pre-feasibility study phase through comparing the preliminary cash-flow calculations for different alternatives.

The capital budget is composed of the investment costs of the anaerobic digestion and upgrading units together with the auxiliary investments (like grid connection, utilities, etc.). Realistic and final feasibility study should be performed only based on the budget offers by the technology suppliers or EPC contractor(s). The preliminary cash-flow calculations provide a necessary and useful guidance for selecting the technology supplier(s) or EPC contractors. For example, comparing IRR for different technology solutions with regard to differences in prices, material and energy balances, utility consumptions, payment terms, etc. will facilitate the selection of the most feasible technology.

The investment budget calculations included in the feasibility study must be complete, well detailed, prepared with proper diligence, containing reasonable reserves which will ensure that the project can be realized with the planned investment budget.

All relevant cost elements must be considered, among them the costs of

- the acquisition of the site,
- earth works,
- establishing the export and import network connections (electricity and natural gas),
- detailed engineering,
- permitting,
- construction, equipment, pipes etc. (including transportation to the site, potential customs clearance),
- instrumentation, control, and automation,
- first set of spare parts,
- gas analysis, local laboratory,
- internal roads,
- fencing,
- fire alarm and fire protection,
- lightning protection,
- energy and material costs for start-up,
- technical documentation, handbook for operation, etc.

Note: the above list is not exhaustive, only indicative. Careful attention is to be given to the fact, that the offers from the technology suppliers/EPC contractors may not include all the necessary items, which could cause additional costs and increase the total capital cost budget.

In **The Example** the following investments costs were included:

Table 30: Example of investment costs budget

Item	AD	Upgrading	Total
Construction	2.365.000	550.000	2.915.000
Machinery for technology	1.950.000	1.530.000	3.480.000
CHP unit	450.000		450.000

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Pipelines	195.000	80.000	275.000
Measuring and steering system	275.000	200.000	475.000
Electricity network connection	80.000	50.000	130.000
Loading machine	150.000		150.000
Roads, fencing	150.000		150.000
Engineering, inspections	170.000	120.000	290.000
Land	100.000		100.000
Other (Inc. Reserve)	150.000	150.000	300.000
Total	**6.035.000**	**2.680.000**	**8.715.000**

Notes:

- the numbers in Table 28. serve as illustrations only, must not be used as a reference,
- for simplicity, the total in the column "upgrading" includes the costs of the natural gas grid connection (split under construction, machinery, pipelines) up to 250.000 EUR.

To get a sense of the investment costs the following simple calculation can be made:

Table 31: Specific investment costs in The Example

Net methane production 1 year	4.057.002	m^3
Net methane production first 10 years	40.164.323	m^3
Total investment	8.715.000	EUR
Investment per unit of net methane produced	**0,217**	**EUR/m^3**

Auxiliary investments will be needed in the period covered by the feasibility studies (i.e. 15 years). While calculating the auxiliary investments, in **The Example** it was assumed that proper, professional maintenance will be consequently provided throughout the operation, what limits the need for replacing parts of machinery.

In **The Example** the auxiliary investments (expressed in percentage of original investment value) were assumed as follows:

Table 32: Auxiliary investments

CHP unit year 8	% of original investment	35
Technological machinery years 6-8	% of original investment	20
Technological machinery years 12-15	% of original investment	30
Measuring & steering equipment year 5	% of original investment	25
Measuring & steering equipment year 10	% of original investment	25

Again, we underline that the numbers in Table 30 above are illustrative only and must not be used as a reference. The forecast for the necessary auxiliary investments must be made in view of the requirements of the selected technology, machinery, and equipment.

In **The Example** the auxiliary investments are not spread evenly among all the years, correspondingly the amount estimated for these financial expenditures is fluctuating year by

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year. It is assumed that the auxiliary investments will be financed from the operating income, thus reducing the cash flow.

In the cash flow calculation of any feasibility study the local (domestic) accounting rules must be followed. For the purposes of illustration, In **The Example** the depreciation calculated with

- 20 years for constructions, pipelines, road,
- 8 years for the CHP, technological machinery,
- 12 years for electricity network connection,
- 5 years for measuring/steering equipment, engineering, etc.

The depreciation drops (correspondingly the tax base increases) from year 9, while the machinery makes out the biggest part of the total investment.

8.4 Operational expenses

8.4.1 Raw materials

The list and costs of raw materials for biogas production is provided in Table 2.

8.4.2 Energy consumption

The energy consumption of the combined biogas to biomethane plant consists of 3 elements:

- Electrical energy
- Thermal energy
- Vehicle fuel

The alternatives for energy supplies have been addressed in Chapter 7.5. In the base case of **The Example** the alternative with biogas fuelled local CHP is selected. The own electrical energy consumption of the technology units is covered by the installed CHP unit, i.e., from out of own electricity generation. (See the electrical energy balance in Chapter 7.5.) In **The Example** the electricity consumption of the AD unit was assumed to be 16,5 kWh/to substrate, while the electricity consumption of the upgrading unit was taken as 0,33 kWh/Nm^3 biogas. (As always in this paper, these numbers are only illustrations and must not be considered as a source of information.)

It is to be noted that the actual electricity consumption depends on

- the selected fermentation technology, first on the consumption of the applied feed-in and mixing equipment and
- on the actual substrate qualities and composition.

In **The Example** the own thermal energy consumption of the biogas plant is covered by the hot water generated through cooling the flue gas and the engine of the CHP units, i.e. out of the co-generated heat.

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The transportation and loading of raw materials and the transportation of the fermentation residue does require vehicle fuel – this consumption depends on the distances between the biogas plant and the agricultural fields. The transportation costs related to transporting the substrates are considered in the unit supply costs of these materials.

8.4.3 Personnel costs

The biogas/biomethane plants do not require numerous personnel being present 24 working hours a day. The daily tasks are limited to the loading of the daily volumes of substrates, to checking the installation, to registering the operational parameters and to taking samples from time to time.

Usually, the local personnel do not include technicians trained for full service and maintenance of the machinery (CHP unit, agitators, mixers, etc.), the local staff does only daily routine checks and small caretaking tasks and calls the service company when needed.

Under this approach (which is characteristic for the biogas/biomethane plants all over Europe) in **The Example** we have calculated with personnel costs in the magnitude of 5 persons, the yearly labour costs were estimated at 30.000 EUR/full time staff, which means 150.000 EUR/year for the biomethane plant.

8.4.4 Maintenance

The maintenance of the machinery is the second biggest item among the operation expenses after raw material supply costs. It is obviously important, that the preventive maintenance is carried out according to the respective schedules and the machinery is kept in best operating conditions all the time.

In **The Example** the maintenance costs for the CHP unit have been calculated at a rate of 1,10 Eurocent/kWh gross electricity production. It is usual that the plant concludes a medium-term service contract with the local affiliate of the producer of the CHP units or with another local professional/authorised CHP company on a lump-sum/operating hour fee basis. The service provider takes care of all planned or unplanned service tasks, replacement of oils and parts. Such a service contract gives the necessary assurance for the plant, that one of the most important parts of the installation is always kept at best operational conditions.

The other maintenance costs can be assumed using general market information. In **The Example** the maintenance costs were calculated based on the investment value as follows:

- maintenance of AD machinery: 2,5% of the invested value,
- maintenance of the biogas upgrading machinery: 5,0% of the invested value,
- constructions (digesters, roads, pipelines, etc.): 0,5% of the investment value.

In the first year of operation the maintenance was assumed at 25% level compared to the following years (to consider that the costs are lower in the guarantee period).

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Table 33: Maintenance cost projection in The Example

CHP maintenance	0,011	EUR/kWh	44.000	EUR/year
Maintenance AD machinery	2,5%	on investment	48.750	EUR/year
Maintenance upgrading machinery	5,0%	on investment	76.500	EUR/year
Spare parts (incl. wear and tear)	20.000	EUR/year	20.000	EUR/year
Maintenance AD constructions	0,5%	on investment	11.825	EUR/year
Maintenance upgrading constructions	0,5%	on investment	2.750	EUR/year
Maintenance total			**203.825**	**EUR/year**

8.4.5 Chemicals and other materials

The anaerobic digestion process of may require application of chemicals: desulphurisation agents, anti-foam materials and potentially other chemicals are needed, that is why this factor is considered in the economic calculations of **The Example** in the range of 10.000 EUR/year.

8.4.6 Transportation of the liquid fraction of the fermentation residue

The liquid fraction of the fermentation residue should be applied preferably on the cultivated fields surrounding the location of the biogas plant. As an indication of this cost element, in **The Example** It was assumed that the transportation cost for the liquid fraction will be at 2,- EUR/m^3. It is essential to include a realistic transportation cost estimate in the feasibility studies, which fully reflects the local circumstances (the possibilities of agricultural partners and the respective transport distances must be cleared in course of the preparation of the feasibility study).

8.4.7 Biotechnological service

It is in the elementary interest of the operator of the biogas plant to keep the biological system in the most efficient and balanced condition, otherwise the biogas generation will fluctuate, the biogas production will fall below the potential of the raw materials. The professional biotechnological service includes the following elements:

- Regular laboratory analysis (twice a month) of the composition of the fermentation mass from the digesters (volatile organic acids, etc.).
- Regular laboratory analysis (once a month) of the fermentation residue for remaining biogas potential (to control the efficiency of the degradation of the organic material);
- Laboratory analysis of every new substrate.
- Continuous analysis of process parameters (biogas yield, biogas composition, material balances etc);
- Recommendations on changing process parameters, substrate composition, etc.

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In **The Example** the costs of the biotechnological service were assumed at 1.000 EUR/month, corresponding to 12.000 EUR/year.

8.4.8 Insurance

The costs of insurance must be included in the cash flow calculations of the feasibility study. In **The Example** insurance was estimated at 0,4% of the original investment. This assumes that the biogas plant is equipped with up-to-date steering and monitoring system, fire-fighting equipment and is taking care of professional, regular maintenance of the machinery.

8.4.9 Banking expenses

In **The Example** the banking expenses related to operations were calculated at 0,3% from the yearly total amount of all incomes and cash expenses.

8.4.10 Administration and overhead expenses

In **The Example** the administration and overhead expenses (management, accounting, etc.) were estimated at 3.000 EUR/month.

The following table illustrates the forecast for the operational expenses under the assumptions and conditions of **The Example**:

Table 34: Forecast of operational expenses in The Example

	EUR/year	Share
Raw materials	1.150.000	67,62%
Maintenance machinery	169.250	9,95%
Maintenance constructions	14.575	0,86%
Spare parts	20.000	1,18%
Chemicals	10.000	0,59%
Energy (electricity)	0	0,00%
Fermentation residue transportation	91.010	5,35%
Biotechnological service	12.000	0,71%
Personnel	150.000	8,82%
Administration, overhead	36.000	2,12%
Insurance, banking	47.754	2,81%
Total	1.700.589	100,00%

In the cash flow calculations of **The Example** no reserve was included for non-foreseen costs. Nevertheless, it is advised to include an unspecified, “reserve” cost position in every concrete feasibility study.

Showing the estimated operational expenses in relation to the volume of net biomethane production is an indicator which every addressee of the feasibility study will find interesting.

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Under the assumptions and conditions of **The Example** the operating costs are at 0,419 EUR/Nm^3.

Table 35: Rough estimation of self-costs in The Example

Net biomethane production	4.057.002	Nm^3/year
Opex per unit of biomethane	0,419	EUR/Nm^3
Capex divided for 10 first year's production	0,217	EUR/Nm^3
Opex + Capex	0,636	EUR/Nm^3
Interest paid divided for first 10 years production	0,047	EUR/Nm^3
Rough estimation of self-costs	**0,683**	**EUR/Nm^3**

The question can be raised how the cash flow calculation in the base case of The Example can show 10,02% IRR at 6,05 Eurocent/kWh if the self-costs of biomethane production in Table 33 is 0,683 EUR/Nm^3. The difference is that the IRR is reflecting the rate of return on the invested own capital (25%), while in Table 30. the total Capex (including the part financed by the non-repayable investment subsidy) is considered.

8.4.11 Cash flow projection

The cash flow projection can be produced for different time durations. In **The Example** the period between 2022 and 2037 is covered. It is assumed that the construction of the plant is completed by the end of 2022 and the biomethane production starts in 2023. For the first year of operation the production level is estimated at 90%.

For simplicity, the cash flow calculation of **The Example** does not include inflation projection. If required, inflation projection can be added, and different inflation rate can be applied to the different revenue and costs components.

The cash flow scheme of **The Example** includes the following steps:

- Revenues
- Direct and indirect costs
- EBITDA
- Depreciation
- EBIT
- Interest paid on credit.
- Amount subject to profit tax
- Profit tax
- Operational cash flow (interest paid, taxed)
- Investment cash flow
- Operational and investment cash flow
- Financing
- Credit service

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- Financing cash flow
- Cash flow (aggregated operational, investment and financial cash flows)
- Feasibility indicators

Notes:

- The relevant domestic regulations regarding depreciation and taxation must be followed – these may be substantially different from the numbers applied in **The Example**, which is provided solely for illustration.
- Companies and banks may apply different cash flow calculation schemes.
- Companies and banks may consider different feasibility indicators in their decision-making process.

8.5 Abatement cost

A recent study by Climact, Valbiom, Biogas-E and Gas.be ('Deep Dive Study Green Gas Platform: a roadmap for anaerobic digestion by 2050') quantified the abatement cost for Belgian biomethane installations. Several scenarios were calculated to assess development possibilities for biogas and biomethane. To identify the most desirable development scenario, the focus was on minimizing production costs at the highest GHG emission reduction. This abatement cost, or cost per ton of avoided CO_2-emissions, is an interesting parameter and can be easily compared with the cost efficiency of other climate measures. Moreover, it demonstrates which production potential is feasible in function of the willingness to pay for CO_2-reduction. For the 23 calculated scenarios for Flanders, the abatement cost varied between - €9 and €565 for a capacity of 200,000 ton fresh material per year. It could be concluded that the advantage of scale is high, that methane emission reduction is extremely important, that the composition of the input streams strongly influences the cost, and that recognition of RENURE-products would be economically beneficial. This study can be consulted via: https://www.gas.be/nl/nieuwsberichten/deepdive-studie-potentieel-biomethaan-belgi%C3%AB.

8.6 Financing

The REGATRACE project provides a „Guidebook on securing financing for biomethane projects" (Deliverable 6.2). In deliverable 6.2 the potential different sources of financing are addressed. Therefore, this chapter on financing is limited to the question: how should financing been handled in the feasibility studies.

As a matter of fact, feasibility studies are crucial in securing financing for a project while they must secure the necessary trust of the investors and financing institutions. The financing chapter of a feasibility study must be tailor-made to the project it covers. To enable fulfilling this role key issues must be studied and cleared in the pre-feasibility study phase, the most important among them:

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- is there a non-repayable investment subsidy available and – if yes – under which conditions?
- is the project qualified for receiving an investment subsidy?
- what is the level of private capital which could be invested into the project and what is the expectation of private investors for repayment and profitability?
- are banks/financing institutions ready to provide credit in form of direct project finance or securities are required from the stakeholders in the project?
- which are the basic requirements of banks/financing institutions for providing project finance (necessary Debt Service Coverage Ratio (DSCR), offered credit terms, such as interest rate, repayment period, grace period, supporting documentation).

Having collected the information on the above issues the feasibility study will determine whether the financing of the project under the given circumstances is possible.

The cash-flow calculation of the feasibility study applies the above listed information collected in the preparatory phase and supposed to confirm that the

- the project has acceptable feasibility indicators under the available conditions of financing,
- the credit service is guaranteed,
- the expectations of the private investors can be fulfilled.

In **The Example** the financing was calculated under the following conditions:

- interest rate: 6 % per annum,
- repayment period: 10 years (excluding the grace period)
- grace period: 18 months
- Interest in grace period: accrued and added to the capital.

Table 36: Key numbers for financing

Total investment cost	8.715.000	EUR
Own funds (25%)	2.178.750	EUR
Non-repayable investment subsidy (30%)	2.614.500	EUR
Credit amount capital	3.921.750	EUR
Interest rate	6	%/year
Interest 6 months 2021	117.653	EUR
Interest 12 months 2022	235.305	EUR
Total credit incl. accrued interest	4.274.708	EUR
Credit service	580.796	EUR/year

The detailed calculation of the credit service in **The Example** is illustrated in Table 35.

Table 37: Estimation of credit service

Year	Outstanding capital	Capital repayment	Interest due	Credit service
	EUR	EUR	EUR	EUR

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2022	4.274.708	0	0	0
2023	4.274.708	324.313	256.482	580.796
2024	3.950.394	343.772	237.024	580.796
2025	3.606.622	364.398	216.397	580.796
2026	3.242.224	386.262	194.533	580.796
2027	2.855.961	409.438	171.358	580.796
2028	2.446.523	434.004	146.791	580.796
2029	2.012.519	460.045	120.751	580.796
2030	1.552.474	487.647	93.148	580.796
2031	1.064.827	516.906	63.890	580.796
2032	547.921	547.921	32.875	580.796
	Total:	**4.274.708**	**1.533.250**	**5.807.958**

Applying the above conditions, the cash flow calculation of **The Example** confirmed that at the assumed set of data the project would be capable of servicing the credit. The resulted DSCR was 1,57.

In case of revamping an existing biogas, plant and converting it to biomethane production the financing of the project is to be secured under different set-up:

- no state aid in form of non-repayable investment subsidy can be expected,
- it is likely that the banks/financing institutions will not require cash capital contribution form the stakeholders, while the existing plant will be accepted as security,
- the costs of revamping of the anaerobic digestion plant must be added to the investment costs of the new upgrading unit (together with the investments needed for natural gas grid connection).

8.7 Feasibility indicators

8.7.1 IRR

As one of the key indicators for feasibility usually the Internal Rate of Return (IRR) is selected. IRR is the discount rate often used in capital budgeting that makes the net present value of all cash flows from a particular project equal to zero. The higher a project's internal rate of return, the more desirable it is to undertake the project. As such, IRR can be used to rank several prospective projects or potential alternatives an investor is considering. Assuming all other factors are equal among the various projects, the project with the highest IRR would probably be considered the best. One can think of IRR as the rate of growth a project is expected to generate. While the actual rate of return that a given project will in practice generate often differs from its estimated IRR rate, a project with a substantially higher IRR value (than other available options) would still provide a much better chance of good return on the investment.

In **The Example**, for the purpose of comparisons min. 10% IRR was considered as desirable, what means that the set of conditions giving an IRR above 10% was seen as offering satisfactory

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return on the investment, while an IRR value below 10% was viewed as a warning signal, that the feasibility of the project might not satisfy the investors and/or the financing institutions.

Under the set of conditions for the base case the in **The Example** (with local CHP) and at biomethane sales revenue of 6,05 EURcent/kWh the calculations resulted in

IRR = 10,02% (first 12 years)

In **The Example** a 10% IRR expectation for 12 years duration was applied as illustration. This must not be seen as a rule or a reference. The IRR expectation and the respective time frame (10 years? 15 years? 20 years?) should correspond to the local market conditions and the requirements of the investors and/or the financing institutions.

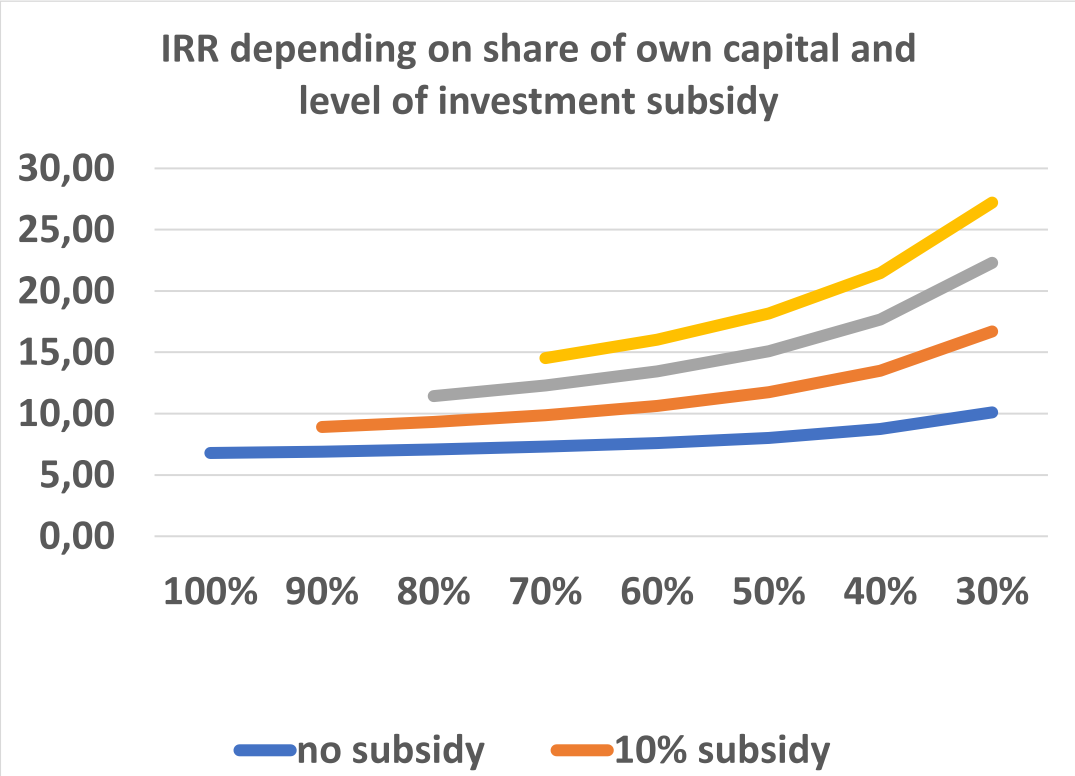

Figure 2: IRR depending on share of own capital and level of investment subsidy

8.7.2 NPV

Another feasibility indicator is the Net Present Value (NPV). The Net Present Value is the difference between the present value of cash inflows and the present value of cash outflows. By other words: the Net Present Value (NPV) of a project is the return on the investment (the sum of the discounted cash flows) less the cost of the investment.

NPV is used in capital budgeting to analyse the profitability of an investment or a project.

NPV compares the value of money (EUR) today to the value of that same money (EUR) in the future, taking a discount factor (for inflation and returns) into account.

About discount factor:

- In private industry, many companies use their own cost of capital (or a weighted average cost of capital) as the preferred discount rate.
- Government organizations typically prescribe a discount rate for use in the organization's planning and decision support calculations.
- Financial officers may use a higher discount rate for investments or decisions viewed as risky, and a lower discount rate when expected returns from a proposed action come with less risk. The higher "discount rate" is a hedge against risk because it puts relatively more emphasis (weight) on near-term returns compared to distant future returns.

The present value of future cash flows requires the implementation of "time value of money" calculations. Cash flows are discounted for the selected number of years to equate future cash flows to current monetary levels. Discounting accounts for the idea that the value of EUR 1,0 today does not equal the value of EUR 1,0 received in one year because money in the present normally offers more earning potential (for example via interest/income bearing savings), than money yet unavailable. Cash flows received further in the future are therefore considered to have a lower present value than money received closer to the present.

In **The Example** NPV was calculated at a discount factor of 10%. If the NPV of a prospective investment calculated at the discount rate satisfying the investor is positive than the project can be accepted. However, if NPV is negative at a given discount rate than the project`s cash flow will result in a number below 10%.

The Net Present Value in **The Example** (base case) was calculated as:

NPV (10%) = 1.298, - EUR

which means that under the applied assumptions the project will likely generate 1.298, - EUR (of present value) in the first 12 years assuming that all future cash inflows are discounted at 10% rate.

Obviously, the discount rate applied for NPV calculation can be any other number than 10% - in view of the relevant local considerations the requirements of the investors and/or the financing institutions.

8.7.3 Discounted Cash Flow (DCF) or Present Value (PV)

Discounted cash flow (DCF) is a valuation method used to estimate the value of an investment based on its future cash flows. DCF analysis attempts to figure out the value of a project today, based on projections of how much money it will generate in the future.

DCF analysis finds the present value of expected future cash flows using a discount rate. A present value estimate is then used to evaluate a potential investment. If the value calculated through DCF is higher than the current cost of the investment, the project could be considered.

Note: the difference between NPV and DCF/PV is that NPV is calculated using the DCF/PV and subtracting the cost of the investment.

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8.7.4 Profitability Index (PI)

The profitability index (PI), alternatively referred to as value investment ratio (VIR), or profit investment ratio (PIR), describes an index that represents the relationship between the costs and benefits of a proposed project, using the following ratio:

$$\text{Profitability Index (PI)} = \frac{\text{PV of future cash flows}}{\text{Initial investment}}$$

The PI is helpful in ranking various project alternatives because it lets investors quantify the value created per each investment option. Under the above formula a profitability index of 1,0 is logically the lowest acceptable measure on the index, as any value lower than that number would indicate that the project's present value (PV) is less than the initial investment. As the value of the profitability index increases, so does the financial attractiveness of the proposed project.

An alternative way of expressing and calculating the Profitability Index is to have Investment required + PV of future cash flows in the numerator and the Investment required in the Denominator. In this case any positive number could be acceptable.

Under the applied assumptions in **The Example** the PV at 10% discount rate, for the first 12 years) is 2.180.178 EUR, which gives a PI of 1,001 in comparison with the invested own capital of 2.178.750 EUR.

Note: the PI of 1,001 resulted from to the way how the calculation of the base case was made: the biomethane sales revenue was calculated to reach min. 10% IRR.

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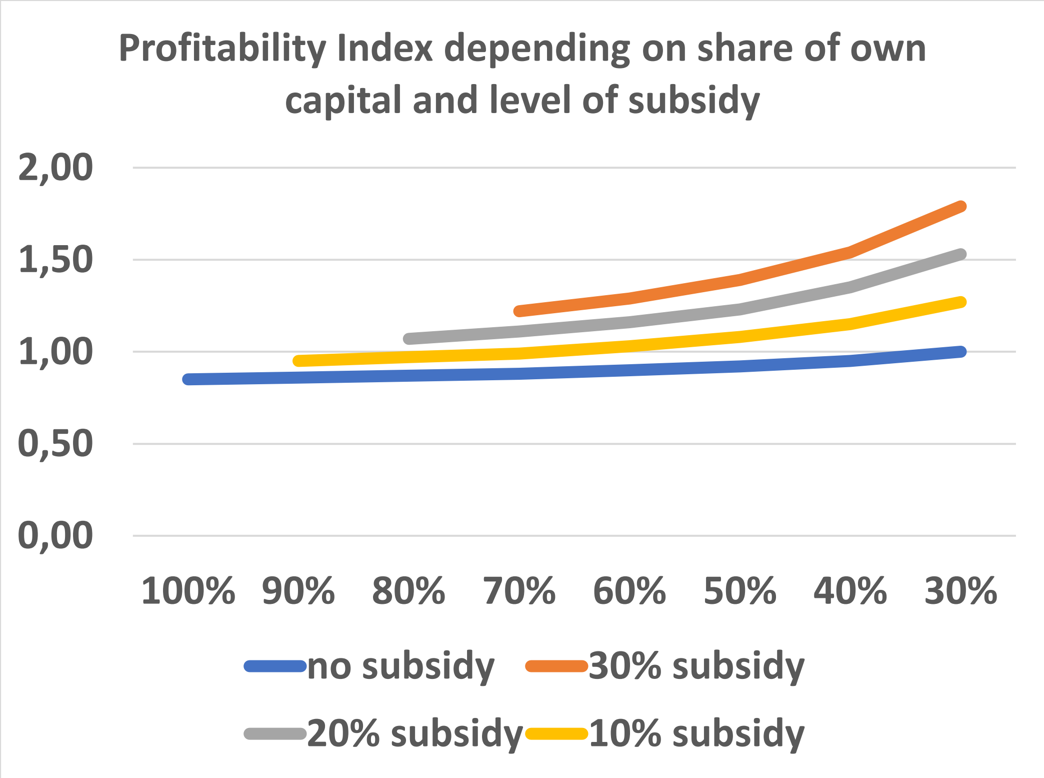

Figure 3: Profitability Index dependig on share of own capital and level of subsidy

8.7.5 Discounted Payback Period (DPBP)

The discounted payback period is another capital budgeting procedure used to determine the profitability of a project. A discounted payback period gives the number of years it takes to break even from undertaking the initial expenditure, by discounting future cash flows and recognizing the time value of money. The metric is used to evaluate the feasibility and profitability of a given project.

Note: the simplified „payback period formula", which simply divides the total cash outlay for the project by the average annual cash flows, doesn't provide as accurate of an answer to the question of whether or not to take on a project because it assumes only one, upfront investment, and does not factor in the time value of money. (The simplified payback period is the amount of time for a project to break even in cash collections using nominal dollars.) Alternatively, the discounted payback period reflects the amount of time necessary to break even in a project based not only on what cash flows occur but when they occur and what discount factor is deemed appropriate.

The calculation of DPBP begins with the estimation of the periodic cash flows of a project shown by period in a table or Excel spreadsheet. These cash flows are then reduced by their present value discount factor to reflect the time value for money concept. This can be done – for example - using the present value function in Excel and a table in a spreadsheet program.

Next, the future discounted cash inflows are netted against the initial investment outflow. The discounted payback period process is applied to each additional period's cash inflow find the

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point at which the inflows equal the outflows. At this point, the project's initial cost has been paid off, with the payback period reduced to zero.

A general rule to consider when using the discounted payback period is to accept projects that have a payback period that is shorter than the target timeframe. A company can compare its required break-even date for a project to the point at which the project will break even according to the discounted cash flows used in the discounted payback period analysis, to approve or reject the project.

8.7.6 DSCR

The Debt Service Coverage Ratio (DSCR) is an important indicator for the financing institution; it shows how far the credit service (repayment of the credit together with the agreed interest) is secured.

$$\text{DSCR} = \frac{\text{EBITDA}}{\text{credit service amount}}$$

In **The Example** (base case with CHP, biomethane sales revenue at 6,05 EURcent/kWh**)**, in the years of the credit repayment (2023-2032) the EBITDA (calculated without inflation adjustment) is forecasted as 909.683, - EUR/year. The credit service (capital repayment + interest) was estimated as 580.796, - EUR/year. Thus, the forecasted DSCR:

$$\text{DSCR} = 1{,}57$$

what would meet the requirement of the banks/financing institutions.

9 Overall risk assessment

The fourth element focuses on the major risks the proposed plan can entail. The overall risk assessment part of a feasibility study examines the different ways your organization can reduce the risk of embarking on the new action.

The overall risk assessment should answer the following questions:

- *What are the major risks associated with the construction and operation?*
- *What is the survival outlook for each of the above risks?*
- *How sensitive are the profits on different risk scenarios?*
- *What are the best ways to minimize these risks?*

The aim is to try to cover all the possibilities and create a risk assessment checklist, which deals with the probability of the risk and the impact it would have on the project. It’s aimed at recognizing the risks that can make or break the project from the smaller, more manageable risks.

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In addition, at launching a new project, the overall risk assessment should also consider one final question. Answering the question "*When can the project be able to support itself without extra financing?*" is an important part of a feasibility study. Self-sufficiency is crucial for business success, as having to borrow can hinder the long-term survivability of the activity.

The construction and operation of a biogas/biomethane plant involves environmental, health, safety, commercial and other risks. With the accumulated experience in the industry these risks are well understood and can be managed if not eliminated. The objective of risk management is to identify all potential risks and put in place suitable measures that will reduce these risks to acceptable levels.

Ensuring the health and safety of employees and the public, and the protection of the environment should be a priority when undertaking any activity, including the construction and operation of a biomethane producing installation.

The failure to identify and manage risks can result in a disproportionate number of accidents and incidents that have a negative impact on the environment, or on the health and safety of site employees and the public. This leads to a negative perception of the industry, and as a result leads to increased wariness of insurers and investors who work with the sector.

The effective risk management should result in:

- Prevention and/or management of pollution incidents and therefore avoidance or reduction of remediation costs.
- Prevention of accidents that could result in harm to employees, prosecution, and business disruption.
- Better staff retention, by demonstrating commitment to their safety and wellbeing.
- Reduced cost of insurance premiums and better insurance policies.
- Improved operational performance, delivering higher quality outputs.
- Better overall financial performance.

The ADBA Best Practice Checklist Risk Management[14] provides a comprehensive description of different risks related to the anaerobic digestion technology and the content can be applied to the biogas-biomethane complex directly. The risk categories detailed on the ADBA paper are:

- catastrophic failure
- environmental risks
- health and safety risks
- commercial and reputational risks.

For project developers it is recommended to study the referred ADBA document.

[14] *http://adbioresources.org/our-work/best-practice-scheme/best-practice-checklists*

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In relation to a biomethane development project the risk management checklist can be specified to include the following items:

Collateral/bankability requirements

- How Is the off take of biomethane and by-products secured? (Government support schemes, long-term purchase agreements, direct marketing positions)?
- Are there long-term substrate supply agreements with sufficient penalties imposed upon default of feedstock supply to cover the losses that would be suffered?
- Is there sufficient insurance over the project risks?
- Is there a long-term land lease agreement if the property is not owned by the project developer?

Permitting and licensing requirements

- Has a basic assessment or full Environmental Impact Assessment been completed?
- Has a waste management licence been obtained?
- Has an air emissions licence been obtained?
- Is there a natural gas grid connection agreement?
- Does the project have a licence for biomethane production?
- Does the project have a construction permit?

Technical considerations

- Does the EPC contractor have sufficient experience/references?
- Is there a guaranteed performance ratio for the plant? Is this guarantee financially secured?
- Does the EPC contract provide for O&M training, has sufficient handover period been allocated?
- Is there a base warrantee on equipment of at least 2 years?
- Has the technical design been reviewed by a qualified independent party?

Contracting requirements

- Have the rights of project properly secured in the respective contracts (land lease, permitting, licences, offtake agreements)?
- Have the construction, O&M, off-take, and feedstock agreements been compiled by parties experienced in biogas/biomethane projects?
- Have the EPC, O&M, off-take, and feedstock contracts been validated by qualified external parties, ideally experienced in biogas/biomethane projects?

Additional considerations

- Has the business model included at least 12 months commissioning time at zero revenue?

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- Is there an environmentally responsible digestate management and placement plan?

10 Sensitivity analysis

The Excel cash flow calculation provides a convenient tool for assessing the impact of different factors on the feasibility of the project.
While assessing the impact of a certain factor all other conditions remain unchanged and the investigated factor is altered. In this Guidance the impact of changes in the following factors are analysed:

- credit interest rate
- investment costs
- investment subsidy
- substrate costs
- efficiency of operation

In **The Example** the base case data are:

- 6% per annum credit interest rate
- 8.715.000 EUR investment costs
- 30% non-repayable investment subsidy
- 1.150.000 EUR/year substrate costs
- 8.000 full load hours per year (an indicator for the efficiency of operation).

10.1 Credit interest rate

The sensitivity calculations are usually performed applying the expected sales price for the primary product (biomethane). With changing the input value for the investigated factor, the feasibility indicators (like IRR, NPV etc.) will change. This is the case in column A of Table 36: the biomethane sales revenue is fixed at 6,05 EURcent/kWh and the interest rate fluctuates between 4 and 8%. As the numbers show, with increased credit interest rate the IRR falls below the required 10%, while lower interest rates impact the IRR positively.

Table 38: Impact of interest rate on IRR in The Example

	A	B
Interest rate %	IRR at biomethane price of 6,05 EURcent/kWh	Biomethane sales revenue required EURcent/kWh
8	4,52	6,21
7	7,44	6,13
6	10,02	6,05
5	12,27	5,98
4	14,31	5,91

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In column B a reversed approach is followed: the IRR remains the same (at the level of 10%) and the biomethane sales revenue necessary to secure this IRR is calculated. As can be seen about 2,6% higher biomethane sales revenue would be needed if the credit interest rate were increased to 8% (from 6%) and – on the contrary – the project could achieve the targeted feasibility at somewhat lower biomethane sales revenue.

In lack of established European biomethane market price information, this Guidance and **The Example** attached to it cannot be based on an estimated biomethane sales revenue. For this reason, the examples of the sensitivity analysis below follow the approach shown under B: the impact of the given factor is expressed through the changes in the biomethane sales revenue necessary for reaching the 10% IRR. By other words: the negative effect of a factor (for example higher credit interest rate) calls for higher sales revenues, while the positive effect (of lower credit interest rate) enables profitable operation at lower sales price.

10.2 Costs of raw material supplies

Table 37 shows the impact of potential changes in the total costs of raw material supplies to the biogas/biomethane plant. As compared to the base case higher substrate costs substantially increase the required biomethane sales revenue. For example, in case of 30% increase of the substrate costs (up to 1.495.000 EUR) and at 30% non-returnable investment subsidy the necessary sales revenue would be abt. 14,4% higher than at the substrate costs assumed in the base case (1.150.000 EUR).

Table 39: Required biomethane sales revenue depending on substrate costs level

Cost level	no subsidy	10% subsidy	20% subsidy	30% subsidy
80%	6,34	6,05	5,76	5,47
90%	6,63	6,34	6,05	5,76
100%	6,92	6,63	6,34	6,05
110%	7,21	6,92	6,63	6,34
120%	7,50	7,21	6,92	6,63
130%	7,79	7,5	7,21	6,92

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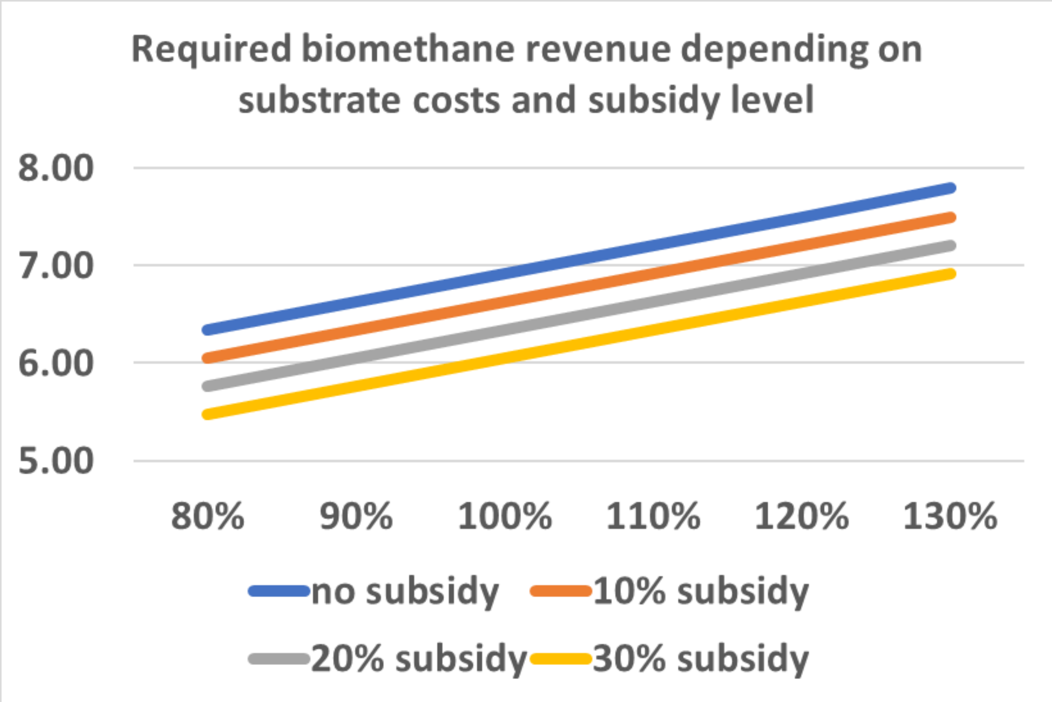

Figure 4: Required biomethane revenue depending on substrate costs and subsidy level

10.3 Investment costs

in The Example the alterations to the investment cost budget in the range of minus 20% - plus 30% were looked at. The comparison with the base case suggests that with the increase of the investment costs (in comparison with the assumed 8.715.000 EUR) substantially higher biomethane sales revenues would be needed for maintaining the feasibility of the project. The impact of higher investment costs is logically higher in cases of lower or no investment subsidy. For example, if the investment budget had to be increased to 11,3 million EUR) and no investment subsidy were available, 7,88 Eurocent/kWh biomethane sales revenue should be generated for achieving the 10% IRR.

Table 40: Required biomethane sales revenue depending on investment costs level.

costs level	no subsidy	10% subsidy	20% subsidy	30% subsidy
80%	6,31	6,08	5,86	5,64
90%	6,61	6,35	6,09	5,85
100%	6,92	6,63	6,34	6,05
110%	7,24	6,91	6,59	6,27
120%	7,56	7,20	6,84	6,49
130%	7,88	7,49	7,10	6,71

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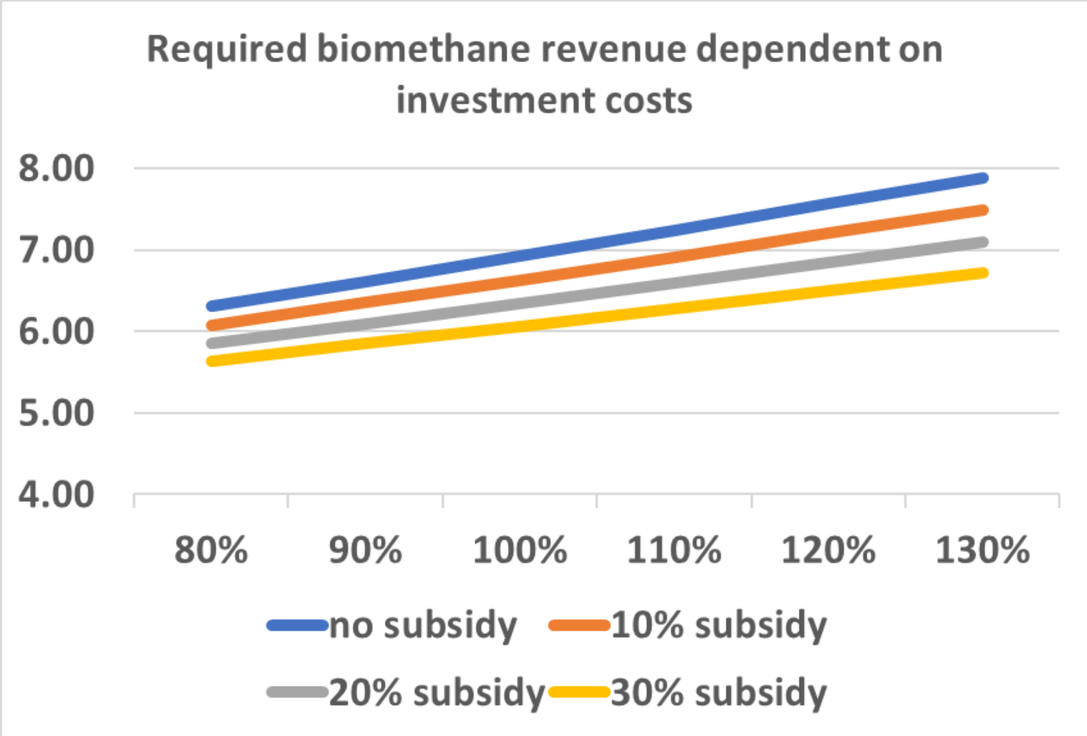

Figure 5: Required biomethane revenue dependent on investment costs

10.4 Investment subsidy

The tables above already illustrate the effect of non-repayable investment subsidy on the feasibility. At 8.715.000 EUR investment costs and 1.150.000 EUR substrate costs the needed biomethane sales revenue is 6,05 Eurocent/kWh if 30% investment subsidy is provided. On the other hand, 6,92 Eurocent/kWh biomethane sales revenue would be needed if no investment subsidy were available.

10.5 Efficiency of operation

Among the sensitivities the potential malfunctioning and disruptions of operations must also be considered. The simplest way of expressing efficiency is to assume a loss of biomethane production due to operational reasons. The correlation between loss of efficiency and worsening of profitability is evident. Without loosening the expectation on the feasibility indicator (10% IRR) the lost production can be compensated only through increasing the necessary biomethane sales revenue, as shown in Table 39.

Table 41: Effect of efficiency of operation on feasibility

Loss of production	biomethane sales revenue
%	required Eurocent/kWh
0	6,05
2	6,18

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4	6,31
6	6,44
8	6,59
10	6,73

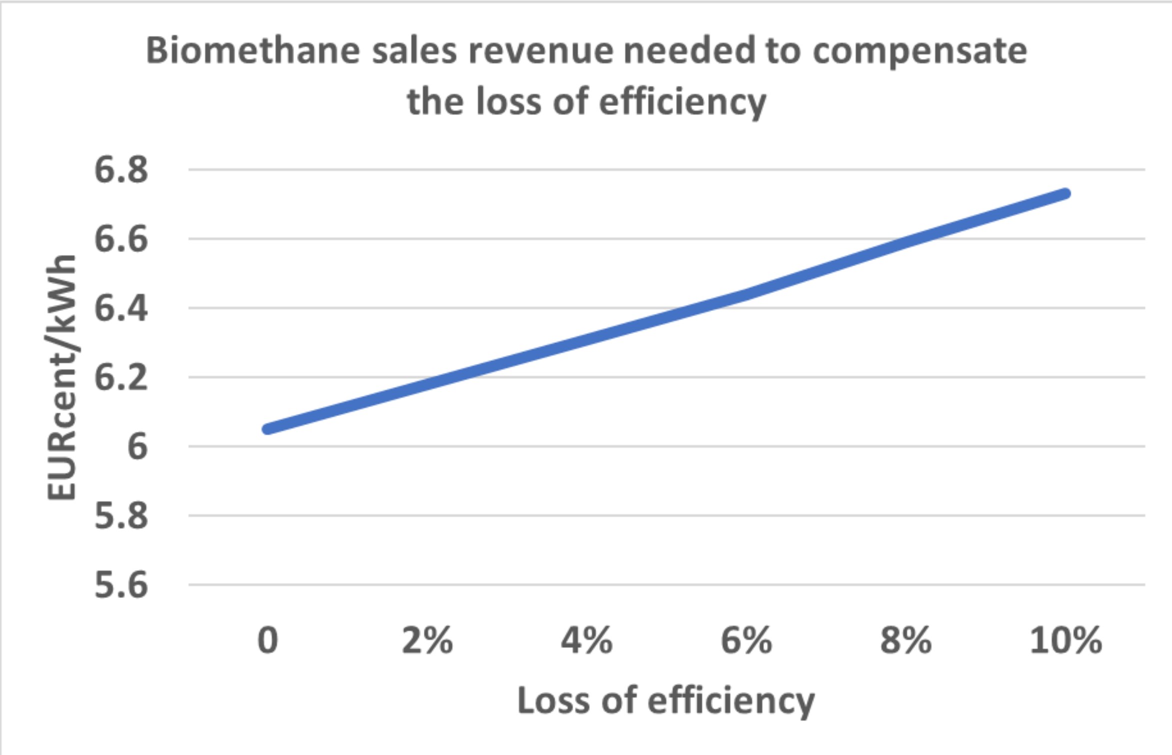

Figure 6: Biomethane sales revenue needed to compensate the loss of efficiency

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Annex 1

English

Part A. Feedstocks for the production of biogas for transport and advanced biofuels, the contribution of which towards the minimum shares referred to in the first and fourth subparagraphs of Article 25(1) may be considered to be twice their energy content:

a) Algae if cultivated on land in ponds or photobioreactors;
b) Biomass fraction of mixed municipal waste, but not separated household waste subject to recycling targets under point (a) of Article 11(2) of Directive 2008/98/EC;
c) Biowaste as defined in point (4) of Article 3 of Directive 2008/98/EC from private households subject to separate collection as defined in point (11) of Article 3 of that Directive;
d) Biomass fraction of industrial waste not fit for use in the food or feed chain, including material from retail and wholesale and the agro-food and fish and aquaculture industry, and excluding feedstocks listed in part B of this Annex;
e) Straw;
f) Animal manure and sewage sludge;
g) Palm oil mill effluent and empty palm fruit bunches;
h) Tall oil pitch;
i) Crude glycerine;
j) Bagasse;
k) Grape marcs and wine lees;
l) Nut shells;
m) Husks;
n) Cobs cleaned of kernels of corn;
o) Biomass fraction of wastes and residues from forestry and forest-based industries, namely, bark, branches, pre-commercial thinnings, leaves, needles, tree tops, saw dust, cutter shavings, black liquor, brown liquor, fibre sludge, lignin and tall oil;
p) Other non-food cellulosic material;
q) Other ligno-cellulosic material except saw logs and veneer logs.

Dutch

Deel A. Grondstoffen voor de productie van biogas voor vervoer en geavanceerde biobrandstoffen, waarvoor ervan mag worden uitgegaan dat hun bijdrage tot het behalen van de in artikel 25, lid 1, eerste en vierde alinea, bedoelde minimumaandelen, het dubbele van hun energie-inhoud is

a) Algen wanneer zij worden gekweekt op het land in vijvers of fotobioreactoren.
b) De biomassafractie van gemengd stedelijk afval, maar niet gescheiden ingezameld huishoudelijk afval waarvoor de recyclingstreefcijfers gelden overeenkomstig artikel 11, lid 2, onder a), van Richtlijn 2008/98/EG.

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c) Bioafval als gedefinieerd in artikel 3, punt 4, van Richtlijn 2008/98/EG van particuliere huishoudens, waarop gescheiden inzameling van toepassing is als gedefinieerd in artikel 3, punt 11, van die richtlijn.
d) De biomassafractie van industrieel afval ongeschikt voor gebruik in de voeder- of voedselketen, met inbegrip van materiaal van de groot- en detailhandel, de agrovoedingsmiddelenindustrie en de visserij- en aquacultuursector, met uitzondering van de in deel B van deze bijlage vermelde grondstoffen.
e) Stro.
f) Dierlijke mest en zuiveringsslib.
g) Effluenten van palmoliefabrieken en palmtrossen.
h) Talloliepek.
i) Ruwe glycerine.
j) Bagasse.
k) Draf van druiven en droesem.
l) Notendoppen.
m) Vliezen.
n) Kolfspillen waaruit de maïskiemen zijn verwijderd.
o) Biomassafractie van afvalstoffen en residuen uit de bosbouw en de houtsector, zoals schors, takken, precommercieel dunningshout, bladeren, naalden, boomkruinen, zaagsel, houtkrullen/spaanders, zwart residuloog, bruin residuloog, vezelslib, lignine en tallolie.
p) Ander non-food cellulosemateriaal.
q) Ander lignocellulosisch materiaal met uitzondering van voor verzaging geschikte stammen of blokken en fineer.

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