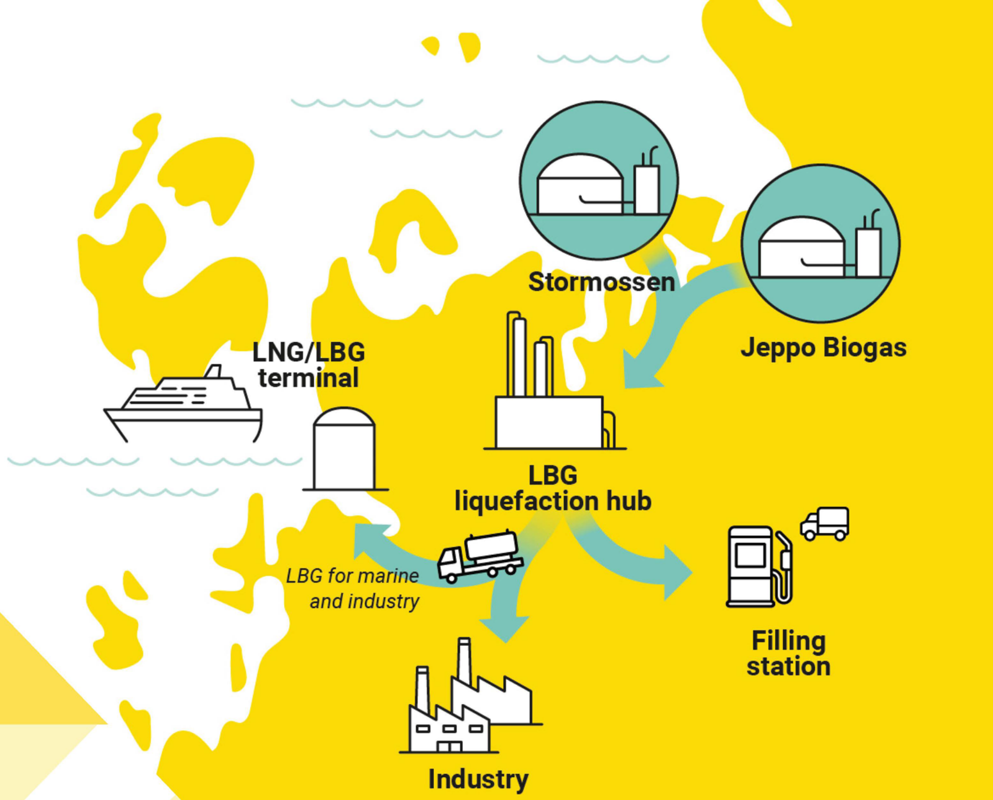

Biogas Utilization Opportunities in Ostrobothnia Region

Findings from the project

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Abstract

This final report summarizes the key results of the "Biogas Utilization Opportunities in Ostrobothnia Region" project, which was conducted from March 2020 - September 2022 by the University of Vaasa.

Reducing greenhouse gas emissions to the atmosphere, replacing fossil fuels with renewable fuels, and reducing waste play a key role in the EU's climate recycling targets. Biogas has a vital role to play in achieving these goals. However, the utilization of biogas in Finland is still limited, and it can be stated that the biogas market and the infrastructure enabling the market operation are still developing. The overall goal of this project was to build new knowledge and create favorable conditions for biogas business and biogas use to grow through techno-economic studies, measurements, and common operation models.

Screening of real-driving emissions of a biogas-fueled city bus and the well-to-wheels analysis showed that up to 90 % greenhouse gas emission savings could be achieved by switching from liquid fossil fuel to biomethane. In addition to the biogas use as a traffic fuel, we investigated the possibilities of industrial operators and the local energy sector to switch to renewable biogas in their operations. To make biogas a realistic alternative for them and other potential new end-users – such as heavy transport and the maritime sector – the production and supply of liquefied biomethane, in particular, needs to be increased. Investments in local biogas liquefaction and a regional biogas pipeline could be the next major step in promoting biogas use in Ostrobothnia.

The greenhouse industry could contribute with biomass waste material to biogas production. Biogas could in return also be employed in combined heat and power applications in greenhouse operations. Nonetheless, the greenhouse industry is already utilizing a lot of other bioenergy in heating. Carbon dioxide capture at biogas production plants is technically possible, and appears to be or become implemented at several sites in Europe.

In the project, three biogas scenarios were created for Ostrobothnia, based on the findings from literature, interviews, and workshops as well as the project's own calculations. The future direction of biogas solutions in Ostrobothnia is still unclear due to legislative issues, investment costs, and lack of knowledge. With sufficient support, the biogas sector can be expected to grow considerably.

Forewords

Christer Wik, Wärtsilä.

Chairman of the Biogas Utilization Opportunities in Ostrobothnia Region Advisory Board

We live in times of change! Energy markets are in turmoil and consumers see escalating prices as well as possible power shortages in the future. Fuel prices for especially methane gas are escalating, reaching levels never seen before! Consumers and producers demand and go towards sustainable energy production, which needs large investments. Pressure has increased also in the marine market to go for sustainable solutions with initiatives from individual states, IMO, EU, banks, and charter owners such as Fit for 55, Poseidon principles, and the Sea Cargo Charter. Taking into consideration that 90% of the world trade is transported by sea and that a ship's mean lifetime is 25 to 30 years we need to act NOW to fulfill the targets of 50% reduction in GHG emissions by 2050 as stipulated by IMO.

Mankind has put a big footmark on the Earth! We need to ensure that biodiversity loss, water and air pollution, global warming, and climate change are reduced to a minimum due to our activities during the Anthropocene epoch we are now living in. One way forward to ensure a sustainable maritime and road transport market is by developing internal combustion engines being able to run on sustainable fuels like green hydrogen, ammonia, or methanol, and this work has started at all engine OEM's!

Another way would be to utilize biogases and reduce GHG emissions with 70 to 100%. That is exactly what has been the focus of this research project, looking into means for boosting biogas production and utilization in the Ostrobothnia region! It is a perfect fit for the demands of many citizens, to aim for a sustainable future!

In this project, the infrastructure development actions have been investigated including a techno-economic analysis of liquefying biomethane as well as a feasibility assessment of a gas pipeline to the liquefaction plant. Different liquefaction solutions on the market were investigated and analyzed from a functionality, reliability, robustness, safety, easiness in operation, operational effectiveness, investment cost, as well as technology maturity point of view. Different scenarios for a gas pipeline between Jepua and Stormossen, have also been investigated and shown to have an advantage with a gas production volume of 50 GWh/a. Another advantage would be that the gas pipeline could later be part of a planned hydrogen gas pipe network around the Baltic Sea!

In addition to this possible utilization of greenhouse waste for biogas production has been investigated and concluded that it could account for up to approximately 5 GWh/a gas production in Ostrobothnia. Any carbon dioxide released in the gasification process could also be utilized in the production of tomatoes and cucumbers in greenhouses since the cultivation demands addition of CO_2 to the air. Burning of biogas to produce electricity for the greenhouses in the near region would close the circuit and create a good example of a circular economy!

Furthermore, interviews and discussions have been held to come up with a scenario around biogas usage and production for the Ostrobothnia region and a lot of good initiatives have started or are under planning thanks to this! Usage of biogas in the city buses of Vaasa has also been investigated, including screening of emissions in real operation. The outcome shows that a CO_2 reduction of around 90% is valid from a well-to-wheel perspective and other emissions would reduce as well ensuring sustainable transport in the region!

Projects like this are needed to create a debate and as a discussion platform regarding developments for common interests and the outcome shows that together we can achieve great results! Now we just need to take the brilliant ideas forward, create something unique in the region, and at the same time do something good for our planet! Let’s aim towards a biogas and hydrogen future including radically expanded biogas production as well as a distribution grid in Ostrobothnia!

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Abbreviations

BMP	biomethane potential
CBG	compressed biogas
CH_4	methane
CNG	compressed natural gas
EGR	exhaust gas recirculation
EIA	U.S. Energy Information Administration
GHG	greenhouse gas
GWP	global warming potential
H_2S	hydrogen sulfide
ISC	in-service conformity
LBG	liquefied biogas
LBM	liquefied biomethane
LN_2	liquid nitrogen
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MR	mixed refrigerant
N_2	nitrogen
O&M	operating expenses
PEMS	Portable Emissions Measurement System
SMR	single mixed refrigerant
TWC	three-way catalytic converter

1 INTRODUCTION

Reducing greenhouse gas emissions to the atmosphere, replacing fossil fuels with renewable fuels, and reducing waste play a key role in the EU's climate recycling targets. Biogas has a vital role to play in achieving these goals. However, the utilization of biogas in Finland is still limited, and it can be stated that the biogas market and the infrastructure enabling the market operation are still developing. Increasing the use of biogas is associated with many issues and uncertainties that slow down the growth of biogas production and the growth of biogas use. For the utilization of biogas to grow significantly, it is necessary to understand, mitigate and eliminate the uncertainties, barriers, bottlenecks, and boundary conditions that slow down development and investment decisions. This project provides new insights into these issues and uncertainties.

In the Ostrobothnia region which consists of 14 municipalities (The Regional Council of Ostrobothnia 2022), there are currently two biogas plants: Stormossen in Mustasaari and Jeppo Biogas in Jepua. These plants produced 46 GWh biogas in 2021 (Jeppo Biogas 2021; Stormossen 2021). There are five gas filling stations that are situated in Vaasa, Mustasaari, Jepua, Pietarsaari, and Vöyri.

The project's overall goal was to build new knowledge and create favorable conditions for biogas business and biogas use to grow through techno-economic studies, measurements, and common operation models. The project's implementation period was 1.3.2020-30.9.2022.

The project objectives were: 1) to determine the conditions for creating new regional biogas infrastructure in the Ostrobothnia region; 2) to verify the environmental performance of biogas as a transportation fuel by measuring emissions from biogas-fueled city buses; 3) to explore the techno-economic feasibility of biogas use in different contexts in the region; industry, waste-energy-sector, and greenhouses; 4) to create common operating models in the biogas business network between different actors; and 5) to develop biogas competence and to increase the number of experts in Ostrobothnia.

The measures of the project were divided into work packages, and the main results of each work package are presented and opened in this report.

- WP1 focused on biogas infrastructure development options in Ostrobothnia, investigating the feasibility and cost of a small-scale biomethane liquefaction plant and the feasibility and costs of a regional gas pipeline in Ostrobothnia.

- The main objective of WP2 was to investigate methane (CH_4) and other gaseous emissions of a biogas-fueled urban bus in real-world conditions. The key advantage of on-board measurements is that they can truly reflect the emission characteristics of vehicles under a wide range of traffic conditions and operating cycles and ambient conditions, including those that are otherwise difficult to replicate in the laboratory.

- WP3 examined the possibilities for industrial companies and the local energy sector to switch to renewable biogas in their operations. The research focused, e.g., on the prospects of local biogas availability and the fuel price forecasts. Moreover, it was investigated whether the greenhouse industry could be part of a circular economy with biogas, both contributing to biogas production through plant waste material and potentially also to act as a biogas consumer, and whether carbon dioxide from biogas upgrading could be utilized.

- WP4 sought to establish dialogue mechanisms between actors who can make a significant contribution to achieving a desired change. Common operating models are presented as descriptions that illustrate the actors and functions needed to bring about the desired change.

- WP5 was about summaring of the results and communicating about the project and its results. This final report was produced as part of WP5. The project and its results have been actively communicated during the project, e.g. by organizing workshops and stakeholder interviews, participating in events, organizing the final seminar and communicating the project on the website of the University of Vaasa and on social media. In addition, communication has included articles in newspapers.

Seven separate reports and one scientific article have been written in the project, which serve as the basis for this final report:

a. Spoof-Tuomi, K. (2020). Techno-economic analysis of biomethane liquefaction processes. Revised March and April 2021.
b. Välimäki, S. (2021). Biokaasuputki Pohjanmaalle – toteutettavuus ja kustannusten arviointi. (Available in Finnish)
c. Spoof-Tuomi, K. (2021). Biometaani jäte-energialaitoksen tukipolttoaineena. (Available in Finnish)
d. Spoof-Tuomi, K. (2021). Biometaani teollisuuden energia- ja koekäytössä. (Available in Finnish)
e. Välimäki, S. (2021). Raskaan kaluston kestävyyden sekä huollon tarpeen selvitys biokaasukäytössä. (Available in Finnish)
f. Spoof-Tuomi, K., Välimäki, S. (2021). Suomalaisen biokaasutuotannon ja biokaasun jakeluinfrastruuktuurin benchmarkkaus. (Available in Finnish)

g. Yorke, A., Luokkanen-Rabetino, K., Berg, P. (2021). Current state analysis and interview analysis.
h. Spoof-Tuomi, K.; Arvidsson, H.; Nilsson, O.; Niemi, S. (2022). Real-Driving Emissions of an Aging Biogas-Fueled City Bus. Clean Technol. 2022, 4, 954–971.

In addition and as new material presented here are chapters on utilization of biogas in the greenhouse industry, and the results from three workshops and common operating models.

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Stormossen (2021). Annual Report 2020. https://ar2020.stormossen.fi/annual_report/vuosikertomus-2020/tulostus/

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2 BIOGAS INFRASTRUCTURE DEVELOPMENT OPTIONS IN OSTROBOTHNIA

Kirsi Spoof-Tuomi

The biomethane industry is attracting growing interest in Ostrobothnia for its potential to deliver clean energy to a wide array of end-users, such as industry, the new Aurora Botnia ferry, and heavy traffic. For them, biomethane offers a sustainable, 100 % renewable alternative for energy production, provided that there is enough high-quality and cost-competitive biomethane available and the gas distribution is wide enough. For biogas to be a realistic alternative for these sectors, the production and supply of liquefied biomethane in particular needs to be increased.

WP1 started with a techno-economic analysis of biomethane liquefaction processes suitable for small-scale production. The case study was based on the existing biogas production capacity in Ostrobothnia. As the investigation progressed, a question also arose on the most sensible ways to transport biomethane to this potential liquefaction plant. Therefore, a feasibility study for constructing a regional gas pipeline in Ostrobothnia was also carried out in this Work Package.

2.1 Biomethane liquefaction: Techno-economic review

The role of natural gas as a fuel for heavy transport is growing with technology development and new gas infrastructure. This also opens up the possibility for the biogas market to grow, especially in the form of liquefied biomethane (LBM). A key advantage of LBM over compressed biogas is its high energy density; LBM is three times more energy-dense and space-efficient than its gaseous counterpart at 200 bar. This entails two significant advantages: The high energy density makes LBM suitable for heavy-duty vehicles, shipping, and even industry, opening up new markets. Besides, the high energy density of LBM makes distribution efficient and economical, allowing for a wider geographical marketing area.

To be able to use biogas as transport fuel, it must first go through cleaning and upgrading processes (Fig. 1). Biogas cleaning is usually considered to be the first step in biogas treatment. Cleaning means the removal of minor unwanted components of biogas, such as H_2O, hydrogen sulfide (H_2S), siloxanes and halogenated compounds. The second treatment – upgrading – aims to increase the energy content of biogas by removing CO_2 (Bailón Allegue & Hinge 2012; Adnan et al. 2019). The final product, biomethane, consists of nearly pure CH_4 (95–99 %). After the cleaning and upgrading processes, biomethane can be transformed into LBM. The focus of this paper is on various biomethane liquefaction processes.

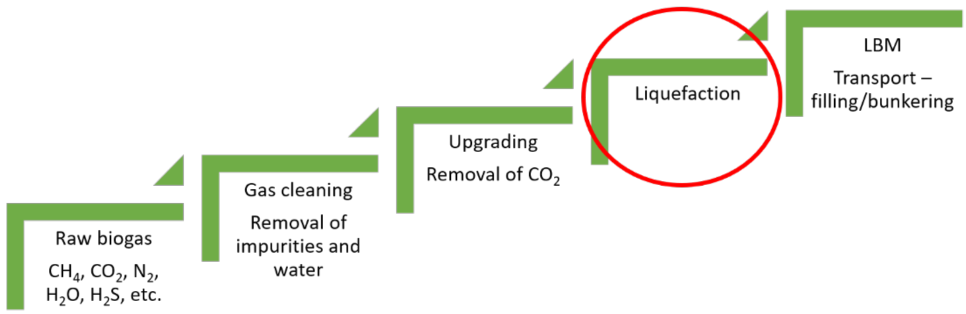


Figure 1. The major steps from raw biogas towards liquefied biomethane. Study boundary in red circle.

Knowledge of liquefaction processes and refrigeration cycles is mature since it has been implemented in liquefied natural gas (LNG) plants for decades (Hashemi et al. 2019). The liquefaction process of biomethane is, in principle, similar to that of natural gas. The two main differences are (Capra et al. 2019):

1. Fluid composition: Raw natural gas is a hydrocarbon gas mixture consisting primarily of methane, but commonly containing varying amounts of other higher hydrocarbons such as ethane, propane, and butanes. For this reason, the condensation of natural gas occurs at varying temperatures, while biomethane – almost pure methane – condenses at a nearly constant temperature.

2. Plant size: The capacity of existing large natural gas liquefaction plants ranges from one to almost 8 million tons per year. The size of biomethane liquefaction plants is significantly smaller, from 0.001 and 0.01 Mt/year.

Indeed, the major challenge for the LBM liquefaction is the scale. The most appropriate method for small-scale liquefaction plants may differ significantly from those used in large-scale applications, as these techniques are neither practical nor economical when applied to small plants (Baccioli et al. 2018). The specific power consumption per unit of LBM plays a key role, but other factors such as the size and compactness and the ease of operation and maintenance, are also crucial (Nguyen et al. 2017).

Based on an extensive literature review, viable liquefaction technologies for nanoscale (<10 tons per day) application could be limited to the following categories:

1. N_2 expander layouts built on different configurations of reverse Brayton cycle
2. Rankine cycle with mixed refrigerant processes
3. Linde cycle
4. Stirling refrigeration

5. Cryogenic liquid vaporization
6. Integrated cryogenic upgrading and liquefaction

In the following chapters, a brief technical description of each technology is presented. Hereafter, the various liquefaction processes are studied from an economic perspective. The life cycle costing (LCC) method was used to analyze the trade-offs between investment cost and future operating costs. To further compare the different processes, the levelized per-MWh costs of liquefaction were defined for each process. Finally, sensitivity analyses were performed to provide a broader view of the economic assessment results and address uncertainties related to investment costs and future expenditure flows.

2.1.1 Liquefaction technology review

Nitrogen expander processes

Nitrogen expander layouts are built on different configurations (e.g., single or dual expansion process, with or without a pre-cooling cycle) of reverse Brayton cycles. The process works by compressing the gaseous refrigerant and then cooling and expanding it to produce temperatures low enough to liquefy the feed gas (Tractebel Engineering 2015). The most common working fluid is nitrogen (N_2).

The single nitrogen expander is the simplest configuration among expander-based technologies (Khan et al. 2017). In this process, N_2 provides the required refrigeration for the entire temperature range of the process, including the pre-cooling, liquefaction, and sub-cooling sections (Roberts et al. 2015). The operating principle is shown in Fig. 2.

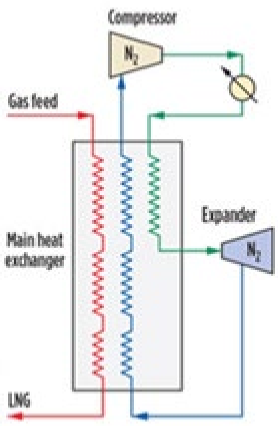


Figure 2. Single-expander N_2 Brayton cycle (Roberts et al. 2015).

The obvious disadvantage of the single N_2 expander process lies in the expansion of the entire working fluid to the lowest temperature, although most is required at higher temperatures. This introduces large temperature differences between the refrigerant and the feed gas, causing high compression energy requirements (Khan et al. 2017). This shortcoming can be remedied by implementing additional levels of expansion, allowing more dedicated refrigeration to each of the temperature ranges (Roberts et al. 2015).

In the dual N_2 expander process, the introduction of the second expander allows splitting the working fluid and causing the expansion of only required part to the lowest pressure, thus saving compression energy (Khan et al. 2017). Fig. 3 describes one such process: A warm expander provides refrigeration at pre-cooling and liquefaction steps, while the second – a cold expander – provides sub-cooling refrigeration (Roberts et al. 2015).

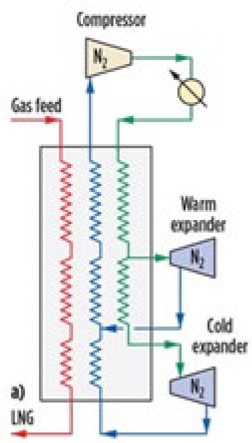


Figure 3. Dual N_2 expander liquefaction process (Roberts et al. 2015).

Although nitrogen is an effective refrigerant in cryogenic applications, its efficiency at higher temperature levels of the liquefaction process is poor. Therefore, many nitrogen cycles include a pre-cooling unit that provides refrigeration duty at these higher temperature levels (Kohler et al. 2014). Adding a pre-cooling cycle, e.g., with propane, CO_2, or ammonia as a refrigerant to the process could reduce power consumption by 15–35 % (He & Ju 2014; Khan et al. 2017; Kohler et al. 2014; Zhang et al. 2020). However, this efficiency increase must be weighed against the increase in cost and complexity (Tractebel Engineering 2015) as well as the potential impact on operability and reliability.

The fast start-up, simplicity, and convenient maintenance of expansion-based layouts (He & Ju 2014) makes them suitable especially for small-scale liquefaction applications. The N_2 expander cycle is straightforward for operating staff to understand, manage and troubleshoot, as the process requires less monitoring and control points and minimal operator intervention compared to, e.g., mixed refrigerant (MR) processes (Pak 2013). In addition, N_2 as a cooling medium can be produced on-site directly from the air, which eliminates the import and storage of hydrocarbon refrigerants. Besides, inert N_2 provides an inherently high level of safety.

One of the world's first LBM plants, Lidköping biogas plant in Sweden, is based on dual N_2 expander liquefaction technology supplied by Air Liquide.

Rankine cycle with mixed refrigerant processes

In mixed refrigerant processes, the refrigerant is a mixture of several compounds, mainly hydrocarbons with low boiling points and nitrogen (Mokhatab et al. 2014). The evaporation process takes place over a temperature glide rather than at a single temperature point as with refrigerants of pure components. It is therefore possible to tune the refrigerant composition so that its evaporation curve matches the cooling curve of the feed gas from ambient to cryogenic temperatures (Nguyen et al. 2018). Refrigeration is always being provided at the warmest possible temperature, resulting in better thermal efficiency.

In the single mixed refrigerant (SMR) process, the feed gas is pre-cooled, liquefied, and sub-cooled in a single cryogenic three-flow heat exchanger. The schematic diagram of the SMR liquefaction process is shown in Fig. 4.

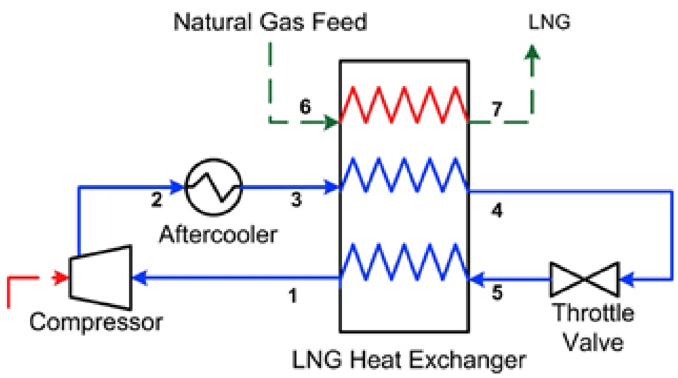


Figure 4. Process flowsheet of the SMR liquefaction process (Khan et al. 2017).

The refrigeration process follows the reverse Rankine cycle: compression–cooling–condensation–expansion–evaporation (Mokhatab et al. 2014). The working fluid is compressed in the vapor phase from the evaporation to the condensation pressure (1 to 2), cooled and condensed to subcooled liquid (2 to 3), and then throttled through an adiabatic valve device (Joule-Thomson valve) (4 to 5). It is then redirected to a heat exchanger where it is fully evaporated to provide the refrigeration effect (5 to 1) (Capra et al. 2019).

SMR is widely used in cryogenic processes for small-scale LNG applications due to its compactness and small footprint (Qyyum et al. 2018). The refrigerant process with phase changes reduces equipment and piping size compared to N_2 loop (Wärtsilä 2020). The power consumption of this process is lower than the N_2 expander cycle one (Ancona et al. 2020). The efficiency advantage of the mixed-refrigerant process is two-folded. The refrigerant composition and temperature glide can be tuned to thermally match the feed gas composition. In addition, the working fluid is mostly in two-phase conditions, and latent heat can be exploited throughout most of the process (Nguyen et al. 2018).

The adoption of cascades of Reverse Rankine cycles, such as pre-cooled mixed refrigerant cycle, or dual-stage cooling cycles can eliminate the large temperature difference at the warm end of the heat exchanger (He et al. 2018). Therefore, such setups can achieve higher system efficiencies than layouts with only one single refrigerant (Nguyen et al. 2017). The downsides of this layout are the higher complexity of the process and the high equipment count and capital cost compared to simple configurations.

Figure 5 shows the schematic of Wärtsilä's NewMR process. The glycol pre-cooling system is incorporated to improve energy efficiency and to ensure stable operation of the MR process.

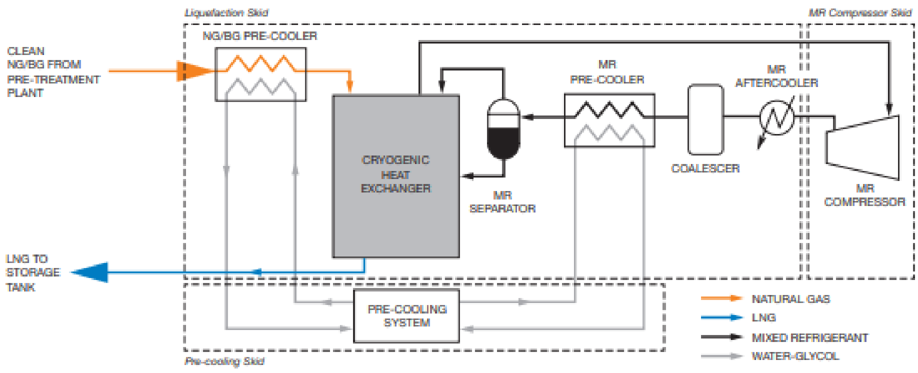


Figure 5. Wärtsilä MR liquefaction technology (Wärtsilä 2016).

So far, the mixed refrigerant-based process dominates the small-scale LBM industry in the Nordic countries. For example, LBM plants in Nes, Skogn and Asker in Norway are based on Wärtsilä's NewMR technology.

Linde cycle

In an open Linde cycle, the gas being liquefied, i.e., CH_4 itself, is used as the working fluid, and a throttling process is used to liquefy the gas. The principal flow diagram is shown in Figure 6. The CH_4 is compressed from ambient conditions to a pressure up to 200–300 bar. This high compression ratio may require several compression and cooling steps. The high-pressure gas then passes through the cryogenic heat exchanger, where it is pre-cooled by the return stream of cold, low-pressure gas. Finally, the cold high-pressure gas is expanded through a Joule–Thomson valve to the desired pressure level, typically 2–3 bar. At the exit of the valve, the flow is in the two-phase (liquid–vapor) region. The liquid phase is collected in the liquid receiver. Uncondensed gas is recirculated and mixed with the feed gas to replace the condensed product and returned to the compressors to complete a new trip through the cycle. (Tybirk et al. 2017; Zare 2016)

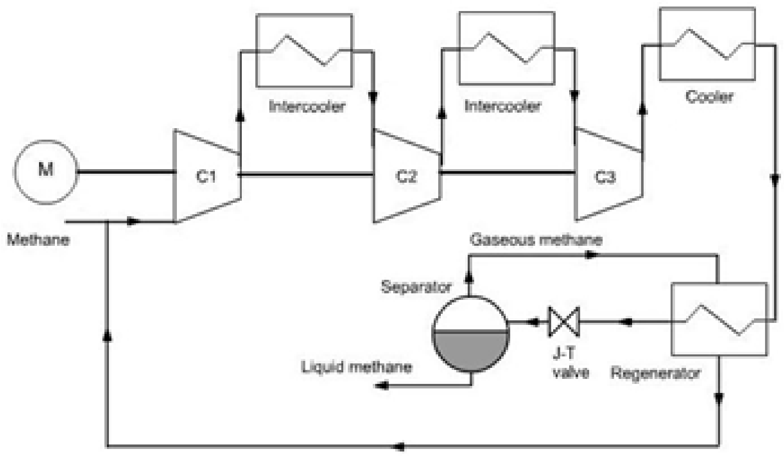


Figure 6. An open Linde cycle, modified from (Zare 2016).

Small-scale liquefaction solutions based on Linde technology are provided by, e.g., Galileo Technologies.

Stirling refrigeration

The cooling power of a Stirling-type cooler is created by the reverse Stirling cycle, i.e., compression and expansion of the working fluid in a closed cycle by mechanical pistons (Stirling Cryogenics 2016). The basic type of Stirling cooler is illustrated in Figure 7.

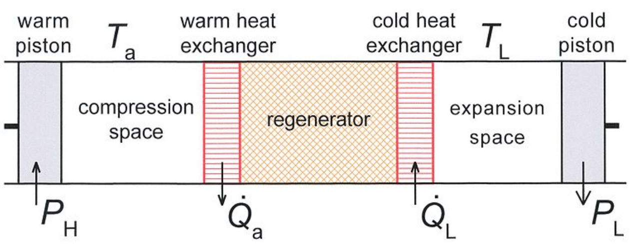


Figure 7. Schematic diagram of a Stirling-type cooler (Wikiwand 2021).

The refrigeration cycle consists of two constant volume processes and two isothermal processes (Capra et al. 2017). The cycle starts when the two pistons are in their most left positions:

1. Isothermal compression: The warm piston moves to the right while the cold piston is fixed. The temperature of compressed working fluid at the hot end is isothermal, so heat Q_a is given off to the surroundings at ambient temperature T_a.
2. Constant volume: The two pistons move to the right. The volume between the two pistons is kept constant. The hot working fluid enters the regenerator with temperature T_a and leaves it with low temperature T_L. The fluid gives off heat to the solid regenerator material.
3. Isothermal expansion: The cold piston moves to the right while the warm piston is fixed. The isothermal expansion occurs and the pressure decreases, so the heat transfer Q_L is taken up. This is the useful cooling power.
4. Constant volume: The two pistons move to the left while the total volume remains constant. The working fluid enters the regenerator with low temperature T_L and leaves it with high temperature T_a so heat is taken up from the regenerator material.

At the end of the fourth step, the state of the cooler is the same as in the beginning, and the cycle is repeated. The feed gas flows through the cold heat exchanger, where energy is extracted, and the gas will liquefy. The typical working fluid in Stirling coolers is Helium.

There are a limited number of Stirling refrigeration applications in the field of methane liquefaction. One such is the StirLNG manufactured by Stirling Cryogenics. These small and compact cryocoolers are modified to produce micro-scale LNG/LBM, typically 200–15,000 kg/day. The biggest drawback is that only small capacity units are available; achieving larger sizes requires the use of multiple units in parallel, preventing economies of scale. In addition, in long-term continuous use, they may be less maintainable than the more common reverse Brayton and Rankine cycles (Capra et al. 2017).

An integrated biomethane conditioning and micro-liquefaction plant relying on Stirling-technology was introduced in 2018 in Foggia, Italy. More references of Stirling cryogenerators can be found in LNG boil-off gas re-liquefying applications.

Cryogenic liquid vaporization

In cryogenic liquid vaporization, the cooling duty is provided by liquid nitrogen (LN_2), which is produced outside the biomethane production plant. LN_2 vaporization is functionally the simplest and less capital-intensive option; it only requires installing a heat exchanger and a liquid nitrogen tank (Capra et al. 2017). A simplified diagram of the combination of gas liquefaction and LN_2 evaporation system is shown in Figure 8.

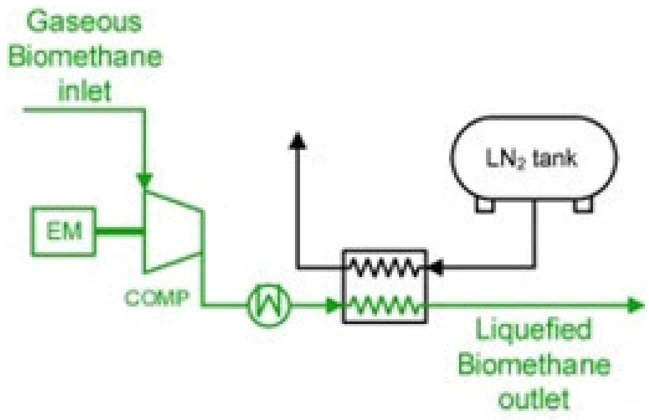


Figure 8. LN_2 vaporization (Capra et al. 2017).

The liquid nitrogen consumption equals 2.5 kg of LN_2 per kg of biomethane, so the LN_2 vaporization technology may be suitable only for plants with low LBM capacity and availability of low-cost liquid nitrogen (Cryotec 2014).

Cryogenic biogas upgrading and liquefaction

In cryogenic upgrading, CO_2 and other unwanted components are separated from the gas flow through condensation. The process is performed in a series of successive temperature reductions, and CO_2 and other impurities are steadily removed from the gas flow as per their boiling points (Kapoor et al. 2019). The final product, almost pure bio-CH_4, is then liquefied. An advantage of this process is that the purified gas is obtained directly at low temperatures, which reduces the cooling requirement in LBM production (Hashemi et al. 2019). Another advantage of using cryogenic upgrading technology is that CO_2 is obtained as a clean liquid by-product to be used in further applications (Pellegrini et al. 2018). Figure 9 shows an integrated cryogenic upgrading and liquefaction system developed by Cryo Pur (Cryo Pur 2020):

1. The incoming raw biogas is first treated with activated carbon filters to remove H_2S. Biogas is then cooled in two steps (-40°C and -75°C) to remove water. VOCs and siloxanes are removed together with water.
2. The dry, pretreated biogas is further cooled to -120°C and carbon dioxide is recovered to ensure that the biomethane reaches the required purity for liquefaction. During this step, pure CO_2 is recovered in liquid form, forming a valuable by-product.
3. The almost pure (>99 %) bio-CH_4 is then compressed and liquefied, and finally stored in a cryogenic vessel.

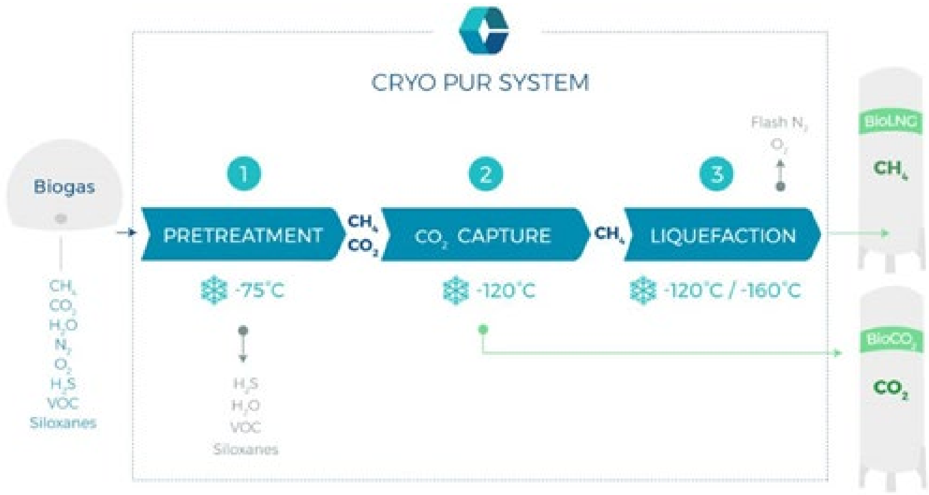


Figure 9. Integrated upgrading and liquefaction (Cryo Pur 2020).

Cryo Pur technology is being adapted for biogas projects with flows ranging from 200 Nm³/h to 2,000 Nm³/h raw biogas (Cryo Pur 2020). The first commercial Cryo Pur plant, with a capacity of 3 tons per day (TPD), was built in 2017 at Greenville Energy's site in Northern Ireland. In 2019, Cryo Pur launched the design of a 7.5 TPD unit for a project in France.

Cryogenic upgrading may be a viable option especially for new plants with no existing upgrading facility in place. Integrating two major energy-intensive processes, upgrading and liquefaction, into one system allows for minimal energy consumption for the complete LBM process (Hashemi et al. 2019).

A list of commercially available liquefaction technologies for applications <10 TPD production, with details of technology providers, main features of the process, and the main technical specifications, are reported more specifically in the individual project report, Spoof-Tuomi 2020, pp. 24–26.

2.1.2 Economic aspects

This section provides an economic analysis of the liquefaction processes presented above. The specific capital costs are harmonized first, followed by the operating costs. Operating expenses (O&M) include energy costs and maintenance costs. Cost data were collected from academic literature and publicly available technical reports and indexed to EUR_{2020} currency.

Capital costs

Capital investment includes the main equipment (refrigeration compressors and drivers, cryogenic heat exchangers, power and control systems), auxiliary equipment, installation, and indirect costs (engineering, freight charges, taxes, and insurance). Fig. 10 summarizes the available specific capital cost data for liquefaction capacities <15 TPD, expressed as €/tons per annum (€/TPA). Most studies considered only the liquefaction system, excluding, e.g., feed gas pre-treatment, cryogenic storage system, and the owner's costs, such as feasibility studies, negotiations with financiers, and approval bodies for permitting.

The average specific capital costs for liquefaction plants with production capacities <15 TPD ranged from 440 to 1360 €/TPA. The LN_2 vaporization and SMR processes cost was at the lower end of the price range, while the Linde cycle represented the upper end of the price range. The average specific costs of N_2 expander-based technologies and pre-cooled MR process ranged from 760 to 990 €/TPA. In the case of integrated cryogenic upgrading and liquefaction process, only the share of liquefaction 1130 €/TPA was included in the costs.

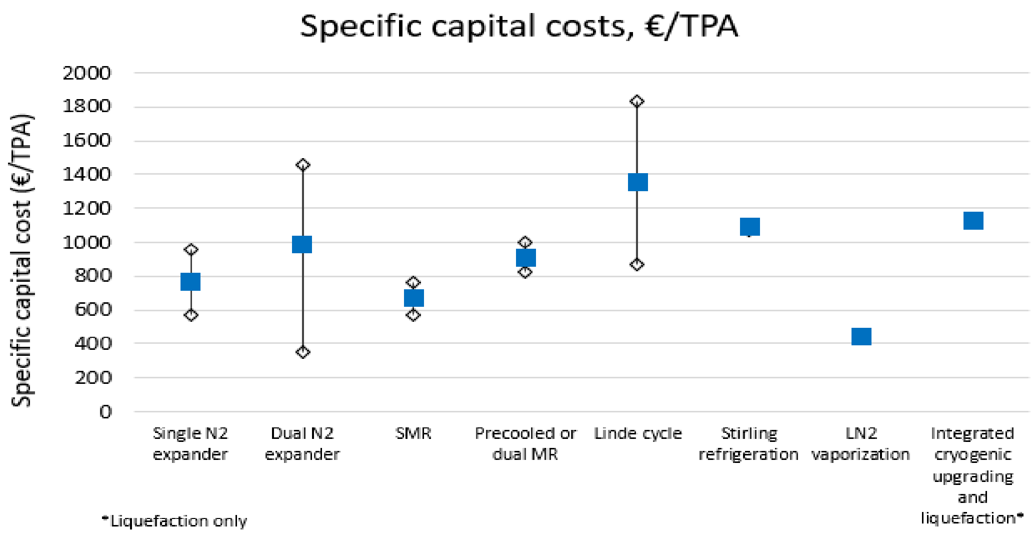


Figure 10. Specific capital costs for liquefaction capacities <15 TPD. Mean values with blue squares, high and low estimates with line segments. Data collected from Fan et al. 2009; Capra et al. 2019; Gong et al. 2012; Hönig et al. 2019; Pasini et al. 2019; Palizdar et al. 2019; Gustafsson et al. 2020; Lee et al. 2020; Himmelstrup 2019; Dioguardi 2013; Coenradie, A. (personal communication Oct. 22, 2020); Prot, C. (personal communication, Aug. 24, 2021).

Operating expenses

The operating expenses of a liquefaction plant consist of feed gas cost, electricity cost, labor cost, maintenance cost, water cycle cost, and refrigerant cost. The costs of cooling water and refrigerant represent only a small part of the total operating cost and are ignored in this study. The exception is the LN_2 vaporization cycle, where the cost of liquid nitrogen is significant and therefore added to the operating costs. The cost of feed gas is also not considered in this study. Thus, the operating expenses in this study include two parts: energy costs, and operating and maintenance (O&M) costs.

Energy cost

Liquefaction processes are energy-intensive processes due to their cryogenic conditions. Indeed, energy costs are typically the highest operating cost. A summary of the specific energy consumption (kWh/kg_{LBM}) associated with various liquefaction technologies is presented in Figure 11. The mean values are marked with blue squares, and high and low estimates with line segments. The energy consumption of liquefaction is closely related to the cooling curves of the processes. In addition, even identical processes with approximately the same capacity can have large variations in specific energy consumption. The explanation is the different process parameters, such as inlet gas temperature and pressure, feed gas composition, compressor efficiency, LBM storage pressure, and ambient temperature (Zhang et al. 2020).

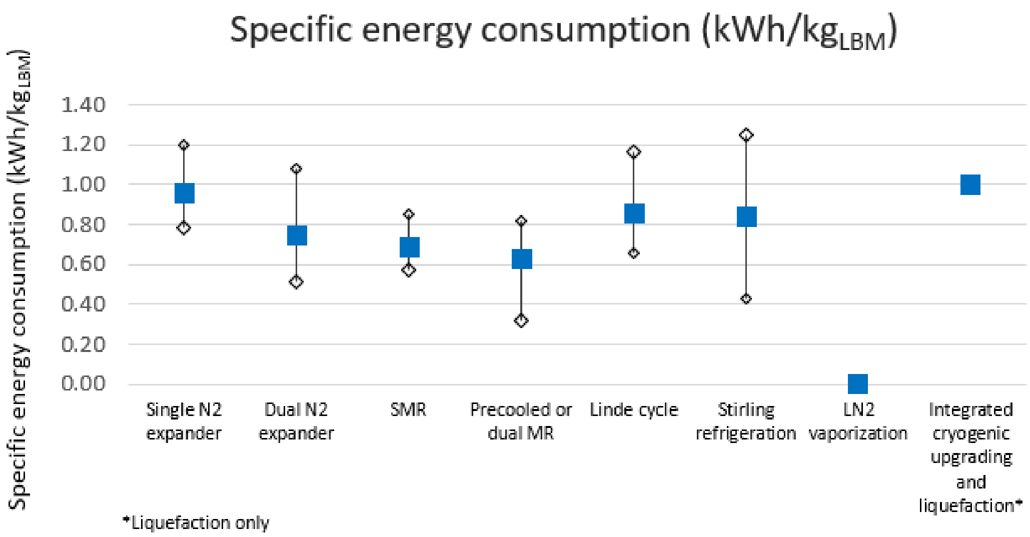


Figure 11. Specific power consumption associated with various liquefaction technologies. Liquefaction capacity <15 TPD. Mean values with blue squares, high and low estimates with line segments. Data collected from Air Liquide 2020; Wärtsilä 2016; Ecospray 2019; Himmelstrup 2019; Stirling Cryogenics 2020; SIAD 2018; Capra et al. 2019; Nguyen et al. 2018; Lee et al. 2020; Palizdar et al. 2019; Pasini et al. 2019; Khan et al. 2013; Morosanu et al. 2018;

Gong et al. 2012; Hönig et al. 2019; Prot, C. (personal communication, Aug. 24, 2021).

Operation and maintenance cost

O&M costs composes of operating work, maintenance work, and maintenance material costs. O&M costs in economic studies of liquefaction technologies (Gustafsson et al. 2020; Lee et al. 2020, Nagy et al. 2017; Pasini et al. 2019; Rehman et al. 2020) range from 2 % to 4 % of investment costs. In this study, O&M costs were assumed to be 2.5 % of the total investment.

2.1.3 Economic analyses of different liquefaction technologies for a 5 TPD plant

The optimal process design is a compromise between investment cost and operating cost. In this section, the economic performances of different liquefaction cycles are investigated based on the LCC model. Please note that only the liquefaction costs were included in the analysis; even though anaerobic digestion and gas cleaning and upgrading account for a significant fraction of the overall costs of the LBM production chain, they are not analyzed in this work.

The case study is based on existing biogas production capacity in Ostrobothnia. A capacity of 5 TPD represents half of the total available capacity.

Methodology

LCC is a useful tool for analyzing trade-offs between the investment cost and future operating cost to get minimum total costs during the project's lifetime. LCC is defined as the sum of the total capital investment (CAPEX) and the present value of future energy and O&M costs (Eq. 1). As a matter of simplification, any incremental investment or decomposition costs at the end of the project over the project's life are not taken into consideration in this study.

$$LCC = CAPEX + \sum_{t=1}^{n} \frac{C_{el} + O\&M}{(1+r)^t} \quad (1)$$

The net present values of future costs were calculated with a discount rate (r) of 5 %. This is expected to cover the financing costs and the general price level increase. The service life (t) of the plant was set at 20 years. CAPEX was calculated by multiplying the average specific capital costs for each process by the plant annual capacity. The future operating expenses include energy costs (C_{el}), based on the average specific energy consumption, and O&M costs. Energy prices were assumed to increase 2 % per year, starting from 0.0862 €/kWh based on Eurostat statistics on electricity prices for non-household customers in Finland in first half of 2020 (Eurostat 2020). For the LN_2 vaporization process, also the cost of liquid nitrogen was included in the operating expenses. The bulk cost of liquid nitrogen was assumed to be 100 €/ton, based on discussions with Finnish LN_2 suppliers. An annual price increase of 2 % was also applied for LN_2. Table 1 summarizes the parameters and assumptions used in the calculations.

Table 1. Assumptions for LCC analyses.

Parameter	Value
Plant operation time	8280 h/year
Liquefaction capacity of the plant	5 TPD
Plant lifetime	20 years
Discount rate	5 %
Operation and maintenance cost	2.5 % of CAPEX
Price of electricity (first half of 2020)	0.0862 €/kWh
Cost of liquid nitrogen	100 €/ton

To further compare the different processes, the levelized costs of liquefaction (LCOL) were defined for each process in €/MWh of LBM. The levelized costs of liquefaction also represent the average revenue per unit of LBM produced that would be required to cover the initial investment and the operating expenses over the expected lifetime of the plant. In Eq. 2, L_{cap} stands for annual liquefaction capacity in MWh of LBM. The lower heating value of LBM is 50 GJ/t (13.9 MWh/t).

$$LCOL = \frac{CAPEX + \sum_{t=1}^{n} \frac{C_{el} + O\&M}{(1+r)^t}}{\sum_{t=1}^{n} \frac{L_{cap}}{(1+r)^t}} \quad (2)$$

Results

The total costs over the entire 20 years life cycle of the liquefaction plant and the cost breakdown for the different liquefaction technologies are shown in Figure 12. The initial capital costs for 5 TPD plant vary between 0.8 M€ and 2.3 M€, representing 10–47 % of the total life-cycle cost. The processes arranged by the initial capital cost, from lowest to highest, are LN_2 vaporization, SMR, single N_2 expander, dual (or pre-cooled) MR, dual N_2 expander, Stirling refrigeration, integrated cryogenic upgrading and liquefaction, and Linde.

Electricity cost accounts for the majority of total operating expenses, except for LN_2 vaporization, for which the price of liquid nitrogen accounts for most operating costs. The net present value of total operating cost ranges from 1.8 to 6.6 M€ over the plant's 20-year service life.

The processes arranged by the total life-cycle cost, from lowest to highest, are SMR, dual (or pre-cooled) MR, single N_2 expander, dual N_2 expander, Stirling refrigeration, integrated cryogenic upgrading and liquefaction, Linde, and LN_2 vaporization.

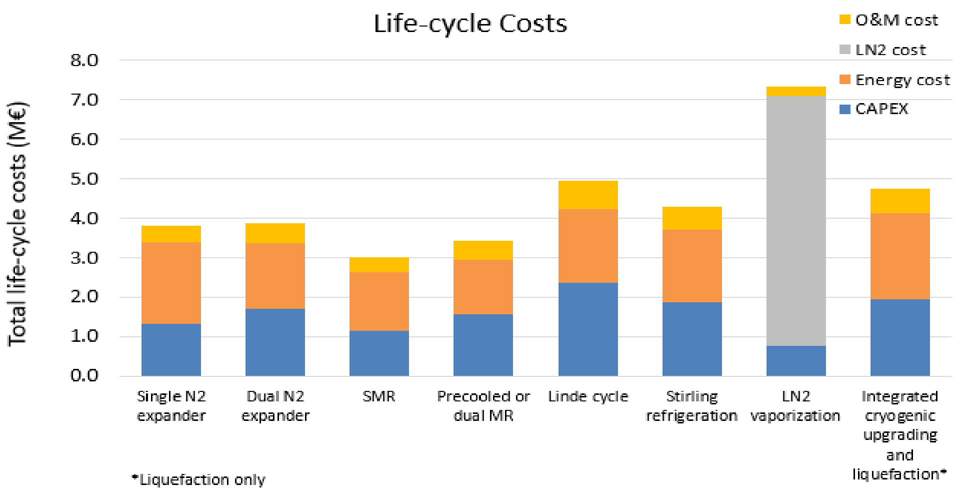
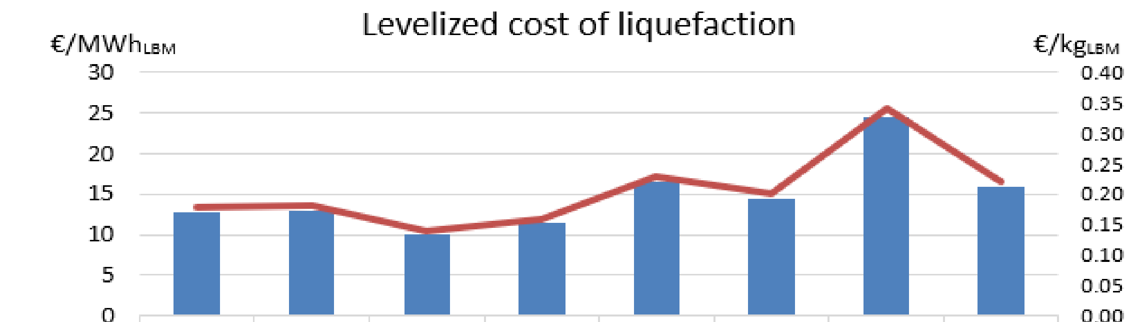


Figure 12. Total life-cycle costs (M€) of a 5 TPD liquefaction plant. Discount rate 5 % and plant lifetime 20 years.

From the economic perspective, the Rankine cycle with mixed refrigerant appears the most advantageous option for the nanoscale liquefaction process, followed by nitrogen expander processes based on the reversed Brayton cycle. The relatively high total life-cycle costs of Linde refrigeration are particularly driven by high investment costs. Liquid nitrogen vaporization is the least capital intensive, but its life-cycle costs depend to a great extent on the price at which liquid nitrogen is available.

The levelized cost of liquefaction, illustrated in Fig. 13, represents the per-MWh cost of constructing and operating a 5 TPD liquefaction plant over its assumed financial life and activity level. For mixed refrigerant processes, the LCOL ranges between 10 and 11.5 €/MWh_{LBM} (0.14–0.16 €/kg_{LBM}), depending on the process configuration. For N_2 expander processes, the LCOL is approximately 13.0 €/MWh_{LBM} (0.18 €/kg_{LBM}). For Stirling refrigeration, integrated cryogenic upgrading and liquefaction and Linde system, the LCOL ranges between 14.4 and 16.5 €/MWh_{LBM} (0.20–0.23 €/kg_{LBM}). In the case of LN_2 vaporization, the LCOL exceeds 24 €/MWh.



	Single N2 expander	Dual N2 expander	SMR	Precooled or dual MR	Linde cycle	Stirling refrige-ration	LN2 vapori-zation	Integrated cryogenic upgrading and lique-faction*
€/MWh	12.77	12.97	10.05	11.46	16.54	14.38	24.56	15.84
€/kg	0.177	0.180	0.140	0.159	0.230	0.200	0.341	0.220

*Liquefaction only

Figure 13. Levelized cost of liquefaction (€/MWh of LBM and €/kg of LBM). Discount rate 5 % and plant lifetime 20 years.

Sensitivity analyses

To provide a broader view of the results of the economic assessment and to address uncertainties related to investment costs and future expenditure flows, a sensitivity analysis was performed against two types of variables:

- High/low investment costs
- Discount rate

High/low investment cost scenario

Most of the available capital cost data for <15 TPD liquefaction plants considered only the liquefaction system, excluding, e.g., pre-treatment, storage system, civil works, and the owner's costs. Also, differences in the availability of existing infrastructure, safety standards, and labor costs for installation may vary. Therefore, a sensitivity analysis considering low and high CAPEX was performed. In the analysis, -10 % – +50 % variability around the initial estimate was applied. The sensitivity of levelized liquefaction costs to the plant capital cost is shown in Fig. 14.

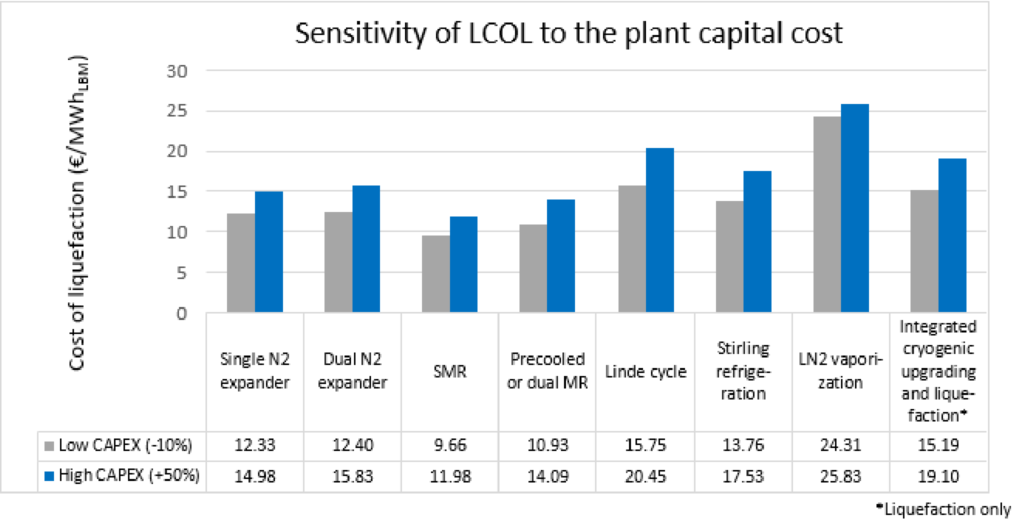


Figure 14. Sensitivity of biomethane liquefaction cost to CAPEX; -10 % – +50 % variability around the initial estimate.

The effect of the discount rate

In the base case, a discount rate of 5 % was applied, representing the minimum return that an investor expects to achieve to cover the cost of finances and the general price level increase. In the sensitivity analysis, a risk premium of 5 % and 10 % was added, leading to the required return (=discount rate) of 10 % and 15 %. For CAPEX, the initial estimate was applied. The results of the sensitivity analysis are shown in Figure 15.

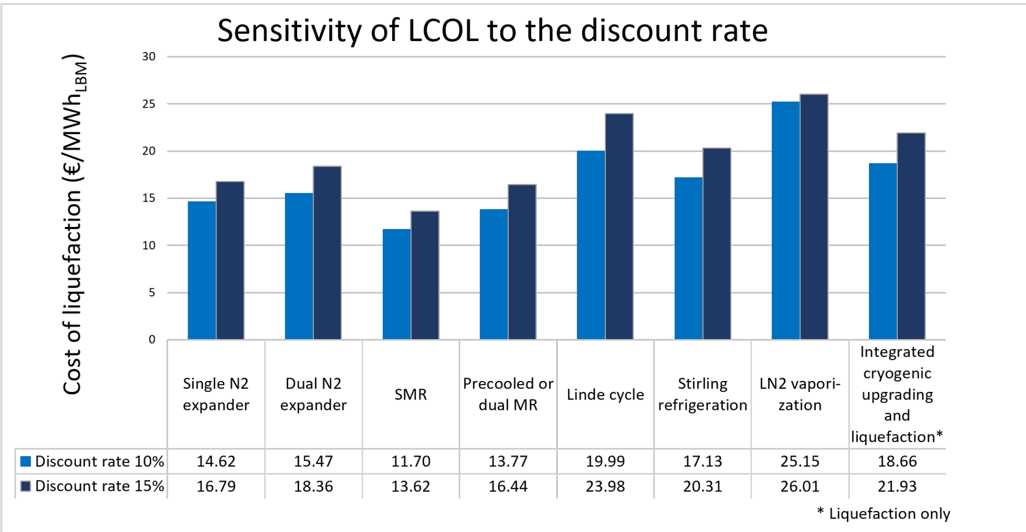


Figure 15. Sensitivity of biomethane liquefaction cost to the discount rate.

2.1.4 Summary and conclusions

The key to the successful optimization of a nanoscale liquefaction project is to find an appropriate balance between process simplicity, easy operation and maintenance, safety, high reliability, and low costs. From a technical and operational perspective, the main findings in this study were:

- The N_2 expansion cycle has the advantages of a simple and understandable process that is easy to use and maintain, as the process requires less monitoring and control points and minimal operator intervention compared to, e.g., MR processes. The working fluid is in gaseous phase, which prevents maldistribution issues in heat exchangers. Moreover, nitrogen is an unreacted refrigerant that provides a high level of safety. Liquid hydrocarbon storage systems are also not required for refrigerant mixtures. The most significant disadvantages of N2 expander processes are the lower energy efficiency compared to MR processes and relatively high space requirements.

- Mixed refrigerant processes had the lowest power consumption of all the processes studied. The MR processes' remarkable efficiency is attributed to the possibility of tuning the refrigerant composition so that its evaporation curve matches the cooling curve of the feed gas from ambient to cryogenic temperatures. The compact SMR process with phase changes reduces the piping size compared to the N_2 loop. Even higher system efficiencies can be achieved by adopting pre-cooling or dual-stage cycles. The disadvantages of such setups are the higher complexity of the process and the high equipment count and capital cost compared to simple configurations. Robust and reliable, mature technology.

- The advantages of the Linde cycle include simple set-up, no need for cooling media, easy maintenance, fast start-up, and boil-off free operation. Furthermore, besides producing LBM, the system can provide compressed gas as needed. In this way, both fuels are simultaneously available. The disadvantage of Joule-Thomson systems is the high compression energy requirement.

- Stirling refrigeration is a robust, stand-alone system, easy to operate, and requires a low amount of operator involvement. The major drawback is that only small capacity units are available. Achieving larger sizes requires the use of multiple units in parallel, preventing economies of scale. On the other hand, the modular design enables a high partial-load capability.

- LN_2 vaporization is functionally the most straightforward and least capital-intensive option, as the liquefaction process uses a considerably small amount of equipment and does not require high-cost turbomachinery. It also offers a high level of safety due to the use of inert gas as a refrigerant. The consumption of liquid nitrogen equals 2.5 kg LN_2 per kg biomethane, so its life-cycle cost depends to a great extent on the price at which liquid nitrogen is available. Best suited for plants with very low capacities and availability of liquid nitrogen.

- Cryogenic biogas upgrading, integrated with liquefaction, is an interesting alternative especially for new plants with no existing upgrading facility in place. Obtaining high CH_4 content and CO_2 recovery account as advantages of this technology. Moreover, integrating two major energy-intensive processes into one system may enable minimal energy consumption for the complete LBM process.

The goal of financial optimization is to minimize total life-cycle cost. For example, minimizing energy consumption by using more or larger heat exchangers or additional cooling cycles increases the complexity of the process, leading to higher capital cost, and thus, does not necessarily result in the lowest total life-cycle cost. Correspondingly, minimizing investment costs does not necessarily lead to the lowest life cycle costs, as was the case for LN_2 vaporization. In this study, an LCC method was used to analyze the trade-offs between the investment cost and future operating costs to get minimum total costs during the project's lifetime. Table 2 provides a brief comparative summary of the costs of the liquefaction technologies studied. Operating and life-cycle costs are presented relative to the most economically advantageous option, SMR.

Table 2. Comparative summary of the cost of liquefaction technologies for 5 TPD plant.

	Single N_2 expander	Dual N_2 expander	SMR	Dual or precooled MR	Linde cycle	Stirling refrige-ration	LN_2 vapori-zation	Integrated upgrading & liquefaction**
Capital cost	Low to medium	Medium	Low	Medium	High	Medium	Low	Medium
Operating cost *	1.4	1.2	1	1	1.4	1.3	3.6	1.5
Total LCC *	1.3	1.3	1	1.1	1.6	1.4	2.4	1.6

*Relative to SMR
**Liquefaction only

2.2 Gas pipeline to Ostrobothnia - feasibility and cost assessment

Recently, the interest in producing and utilizing liquefied biomethane as a clean fuel for the shipping sector, industry, and heavy transportation has increased in Ostrobothnia. As a result, biogas actors operating in Ostrobothnia have discussed the possibilities of establishing a centralized jointly owned biomethane liquefaction plant in the area. However, transporting biomethane from several different producers to this centralized plant has raised questions about the most cost-effective way to handle gas transportation. Therefore, there was a need to study the feasibility of a regional gas pipeline and its construction costs.

This study aimed to assess the feasibility and costs of the gas pipeline in Ostrobothnia. The report introduces a proposal for the pipeline route and the location of the liquefaction plant, which was also still an open question. The pipe pressure, the material suitable for the gas pipeline, and the pipe diameter were determined based on the capacity of the planned biogas liquefaction plant. A cost estimate was made for the selected pipeline route, and the investment and operating costs of pipeline transmission were compared to the costs of distribution of compressed biogas (CBG) by road. The transmission costs were estimated using the annuity method. In addition, the paper presents different cost scenarios for the transmissions methods to describe the effects of different factors on the final cost estimate.

Finally, the report addresses the suitability of methane pipeline for hydrogen transmission in the future.

2.2.1 Gas transmission methods

Pipe transmission

Gas can be transported in underground gas transmission and distribution pipelines. A compressor raises the gas pressure at the production plant, and the gas flows in the pipe from high pressure toward a lower pressure due to a pressure difference.

In addition to the actual pipeline, pipeline transmission requires many devices and systems, such as a compressor that creates pressure in the pipe, chromatography for measuring the quantity and quality of the gas, gas odorization, and valve stations with safety cut-off devices at certain distances to cut off the gas flow, e.g., in leakage and maintenance situations. In addition, the gas network requires a variety of remote monitoring systems to monitor network status.

Biogas is equated with natural gas in Finnish legislation (Tukes 2022), so the regulations concerning natural gas and its transportation also apply to biogas. These regulations are issued in the Government Decree on Safety of Handling Natural Gas (551/2009). Following the natural gas legislation, the design pressure of the gas pipeline must be selected to be at least equal to the pressure to which the pipeline is subjected under operating conditions. Likewise, the design pressure of piping fittings and actuators must equal the maximum allowable operating pressure of the piping. In addition, specific minimum depths of soil coverage have been set for underground pipes, depending on the environment of the pipe installation site. There are also recommended safety distances from gas pipes to buildings and roads. (Finnish Gas Association 2014.)

In addition, environmental impact assessment plays a key role in a gas pipeline project. The gas pipeline route should also be generally acceptable, treat landowners as equitably as possible, and take into account possible future land use. The right to use the land required for construction is acquired from landowners based on the Redemption Act. (603/1977).

CBG transportation

Alternatively, biomethane can be transported by trucks in high-pressure gas transportation containers. To maximize the amount of gas transported, it is traditionally compressed to a pressure from 200 to 250 bars, giving a 200-250-fold volume contraction.

In addition to gas containers and transportation fleet, the equipment required for biomethane container transportation includes high-capacity CBG compressors. A pressure reduction unit for a controlled reduction of gas pressure is also needed at the user end.

The advantage of container transportation is the flexibility of route choices; route changes or introducing new routes do not require any new investments if the gas volume remains the same. However, the operating costs of container transportation are more sensitive to changes compared to gas pipe transmission, as, e.g., vehicle fuel prices and CO_2 taxation may change significantly over the years. In addition, the volumes of gas transported usually cannot be increased without new investments, as the gas pressure cannot be increased, which is not a problem with an adequately sized gas pipeline.

2.2.2 Cost structures of pipeline transmission and CBG transportation

The costs of pipelines and CBG transportation can be divided into capital expenditures (CAPEX) and operating expenses (OPEX). However, there are some fundamental differences in their cost structures that are highlighted in this Section.

Gas pipeline

Capital costs of gas pipeline include piping materials, construction work, compressors and other equipment, engineering, supervision, administration and overhead, interest, allowances for funds used during construction, and regulatory fees (Ulvestad & Overland 2012). In addition, the disadvantages for landowners during construction have to be compensated. The operating cost of the pipeline consists of the compressor's energy consumption, maintenance and pipe repairs, monitoring and control, and possible land lease to landowners (Ulvestad & Overland 2012).

The construction cost of a pipeline may vary significantly depending on the region. Differences in terrain, labor costs, and population density make pipeline economics highly project specific.For instance, the cost of a gas pipeline running through a densely populated urban area is higher than the cost of a pipeline of the same length crossing a rural area. Hence, pipeline designers are often reluctant to generalize the cost of constructing pipelines (Ulvestad & Overland 2012).

In the case of gas pipelines, the investment costs are high, due to the extensive construction work, while the operating costs of the pipeline are low. A major advantage of pipe transmission is the possibility to increase the gas transmission capacity at negligible investment cost if, e.g., an expansion margin for pressure resistance has been considered in the design and construction phase.

CBG transportation

Unlike in the case of a pipeline, container transportation costs are more evenly distributed between capital and operating expenses. The major CAPEX consists of high-pressure gas containers and CBG compressor(s) purchases. At the user end, a pressure reduction system is also required. In this study, any investments in the transportation fleet are not included; the transportation service is assumed to be purchased from a transport company.

In the case of CBG transportation, operating costs are rising due to the transport fleet's fuel and operating costs and the high energy needs of gas compression. A significant factor in OPEX is the transportation distance. It should also be noted that the transport distance is twice the distance between the production facility and the end-user, as the vehicle must return empty to the production facility. Transport masses are also a significant factor in operating costs. The total weight of the transportation can be influenced by using lightweight (and more expensive) composite gas cylinders instead of heavy steel cylinders.

As the maximum gas volume to be transported in one delivery is limited, increasing amounts of CBG would lead to a daily need for multiple rides, in addition to which additional containers may have to be acquired, thereby affecting both OPEX and CAPEX.

2.2.3 Biogas pipeline to Ostrobothnia

The biomethane pipe considered in this work is led to a biomethane liquefaction plant with an annual capacity of 50 GWh. The location of the liquefaction plant was set in the Vaasa area due to the versatile industrial activities in the area, and the port. Biomethane for liquefaction is primarily produced by Jeppo Biogas Ab and Ab Stormossen Oy. In addition, there is a large potential for biogas production from agriculture wastes in Ostrobothnia. In the future, biogas produced on farms could be fed directly into the pipeline employing connecting pipes. This section assesses the implementation of a gas pipeline with annual transmission volumes of 25–100 GWh in Ostrobothnia.

Pipeline route

The pipeline's starting point was set in Uusikaarlepyy beside the Jeppo Biogas plant and the endpoint in Mustasaari beside the Stormossen biogas plant. The distance between the sites is 56 kilometers. The proposed gas pipe route is shown in Fig. 16. The route was formed based on satellite images from Google Maps so that it passes as little as possible through, e.g., agricultural land and population centers.

The design length of the pipeline was set to 60 kilometers, as the final pipeline route may differ from the proposal and be longer, e.g., due to environmental and permit issues. Based on the satellite imagery provided by the Google Maps interface, the terrain in the route is mostly flat and consists mainly of forests and fields. Closer to Vaasa, the proposed route bypasses a few small settlements. In addition, the route crosses five watercourses. Water bodies are small rivers, and the gas pipeline could be placed at the bottom of these.

The minimum depth of soil coverage for a gas pipeline operating at pressures above 4 bar is one meter (Finnish Gas Association 2014), and most of the pipe could be buried at this depth. In the case of fields, the minimum depth of soil coverage is 1.20 meters, and in the case of ditches and streams, 0.60 meters measured from the bottom of the ditch or stream. The proposed route does not hit heavily trafficked roads, so one meter would be enough to undercut also the roads encountered by the pipeline.

Figure 16. Proposed gas pipeline route between Jepua and Stormossen biogas plants.

The proposed pipeline route has no apparent obstacles or specific challenges for constructing the gas pipeline. At the beginning of the actual pipeline project planning, of course, a more accurate route survey should be carried out to determine the soil composition. For example, the presence of rocks or boulders in the terrain was not assessed in this study, and hence, their potential cost impact could not be assessed. In addition, the construction of the gas pipeline will also require special attention in groundwater areas that the route is crossing.

Pipe size, operating pressure, and piping material

The gas volume flow was calculated based on different annual gas transmission quantities (Table 3). The methane content of the gas transmitted was assumed to be 97 %. The net calorific value of methane is 10 kWh/m^3.

Table 3. Gas volume flows on different annual gas transmission quantities.

GWh/a	m^3/a
25	2 577 320
50	5 154 639
75	7 731 959
100	10 309 278

The recommended pipe diameter (D) was calculated based on the gas volume flow (qV) and the gas flow velocity (v) according to Equation 3.

$$D = \sqrt{\frac{4qV}{\pi v}} \tag{3}$$

Figure 17 shows the calculated pipe inside diameters at different annual gas flow rates as a function of operating pressure. A gas flow velocity of 2 m/s was applied in the calculations.

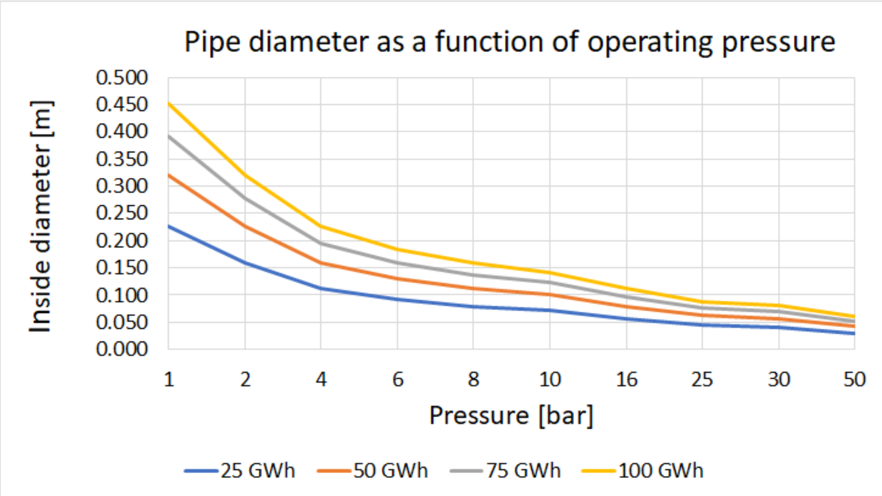


Figure 17. The effect of operating pressure on pipe diameter.

Both steel and plastic materials are used for natural gas distribution mains. Steel is the material used in high-pressure (15–100 bar) natural gas transmission systems, but plastic pipes have predominated the low-pressure gas distribution systems during the past decades. In Finland, the maximum operating pressure for plastic pipes is set at 8 bar. The most used nominal diameters for plastic gas pipes are, e.g., DN125, DN160, DN200, and DN250 (Finnish Gas Association 2014). With a flow velocity of 2 m/s and operating pressure of 4–8 bar, all studied annual gas volumes (25–100 GWh/a) are suitable for these pipe sizes. Due to the significant material cost benefits of plastic pipes over steel, a polyethylene PE100 graded pipe was chosen as the piping material in this report. Another advantage of plastic pipes is their corrosion resistance.

2.2.4 Cost analysis

In this Section, the investment, operating, and service and maintenance costs for pipeline transmission and CBG transportation are defined and compared. To convert the initial investment into a fixed annual cost, the annuity method was used. The annuity was calculated by multiplying the total investment cost by the annuity factor (*I*) (Eq. 4):

$$I = \frac{(1+i)^t \cdot i}{(1+i)^t - 1} \tag{4}$$

where *i*=interest rate and *t*=holding period.

To directly compare the annual costs of gas pipeline transmission and CBG transportation, a common interest rate of 6 % and a holding period of 10 years were applied for both investments. The selected period suits the actual payback time for the CBG alternative, as the service life of gas pipelines is several decades. However, the alternatives can be directly compared using the same interest and holding values.

The following Chapters present the cost estimates for both cases. In addition to the total costs, the investment, operating, and maintenance costs are presented separately to clarify the distribution of costs. The maintenance costs were set at 2 % of the initial investment in both cases.

Pipeline transmission

It is not easy to accurately estimate the construction cost of a gas pipeline in advance without a detailed route plan and a comprehensive survey of terrain and terrain conditions. However, various specific costs for constructing a gas pipeline have been presented in the literature. For example, Haimila (2015) suggests that the cost of material, excavation, and installation for PE100 plastic pipe is 75–200 €/m. Hengeveld et al. (2014) presented the gas pipeline costs at different diameters and different sites, broken down according to the level of installation difficulty, shown in Table 4.

Table 4. Pipeline diameters and cost (Hengeveld et al. 2014)

Outside diameter (mm)	Inside diameter (mm)	Easy €/m	Moderate €/m	Difficult €/m
110	90.0	40	100	160
160	130.8	80	120	170
200	163.6	98	134	210
250	204.6	123	198	258

This work considered a 160 mm inside diameter PE100 plastic pipe with a maximum operating pressure of 8 bar. At an operating pressure of 4 bar, the pipe will transport 50 GWh of biomethane per year, and by increasing the operating pressure to 8 bar, the capacity can be doubled. Based on the above, the cost estimate of 130 €/m, corresponding to a pipe with an outside diameter of 200 mm and moderate installation difficulty, was selected from Table 3. In addition to the pipe material and the excavation and installation costs, the specific cost of the pipeline was expected to include all equipment and systems required for the operation of the pipeline, such as valve stations and monitoring and control equipment. The design length of the pipeline was set at 60 kilometers. The investment cost (*I*) of a compressor was determined according to Eq. 5 (Hengeveld et al. 2014):

$$I = 111.257 + 0.1469C \tag{5}$$

where *C*=compressor capacity in m^3/h.

The input data used for estimating the cost of constructing a gas pipeline are summarized in Table 5.

Table 5. Input data for pipeline cost estimation**.**

Parameter	Unit	Value
Annual gas volume	GWh	50
Pipe length	km	60
Specific cost	€/m	130
Pipeline investment cost	€	7 800 000
Compressor investment cost	€	200 000
Service and maintenance (of total investment cost)	%	2

Table 6 presents the annual cost of construction and operation of the gas pipeline. The electrical energy demand for gas compression is 0.0483 kWh/kg (Hengeveld et al. 2014) and the price of electrical energy 0.12 €/kWh.

Table 6. Breakdown of annual costs of pipeline transmission. Time period 10 years.

Initial investment		
Pipeline	€	1 059 770
Compressor	€	27 174
Total	€	1 086 944
Operating expenses		
Compression	€	21 511
Service and maintenance		
Pipeline	€	156 000
Compressor	€	4 000
Total	€	160 000
Cost breakdown		
Investment	€	1 086 944
Operating and maintenance	€	181 511
Total costs	**€**	**1 268 455**

The cost distribution shows a large share of capital costs compared to operating costs, typical for pipeline investments. Operating costs, especially in gas pipelines with low operating pressure, are low because little energy is required to compress the gas. Indeed, the dominant factor in the annual cost estimate is the specific cost of the gas pipeline. The impact of specific costs on annual costs is highlighted in Table 7.

Table 7. Impact of specific cost of gas pipeline on annual costs. Time period 10 years.

Specific cost	90 €/m	130 €/m	200 €/m
Initial investment	0.761 M€	1.087 M€	1.657 M€
Operating expenses	0.021 M€	0.021 M€	0.021 M€
Service and maintenance	0.112 M€	0.160 M€	0.244 M€
Total	**0.894 M€**	**1.268 M€**	**1.922 M€**

CBG transportation

CBG transportation costs depend on gas volumes, as it determines the capacity and number of containers required and the number of trips. As in the pipeline case above, the cost estimate for CBG transportation is based on an annual gas volume of 50 GWh. The transportation distance by road is 65 km. Due to the high gas volume and a long transportation distance, lightweight composite gas cylinders were chosen as the basis for the cost estimate. The specific prices of composite trailers vary around 50-70 €/Nm^3 (Hetland & Bjørlykke 2012), (Fig. 18).

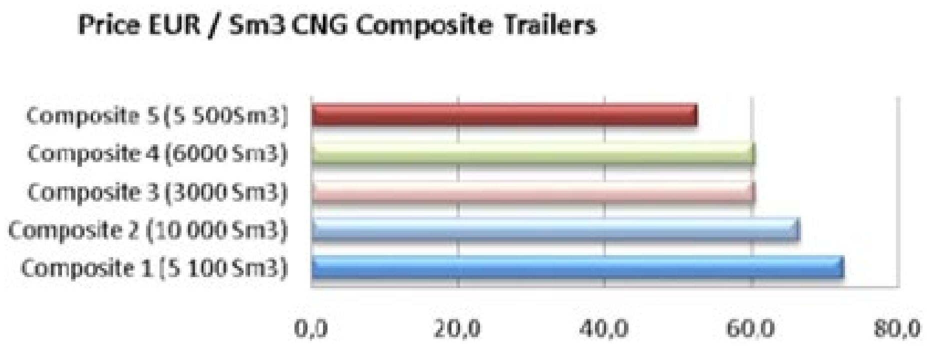


Figure 18. Specific prices of composite trailers (Hetland & Bjørlykke 2012).

The capacity of the CBG containers was chosen to be 7100 Nm^3, and the specific cost 60 €/Nm^3. The number of containers required is five; in this case, there would always be two containers at the biogas plant to be filled and two to be emptied at the liquefaction plant, and the fifth container would ensure continuity of gas supply in the event of a disruption.

Compared to pipeline transmission, CBG transportation requires a more efficient compressor. In addition, a separate pressure reduction system is required at the gas operating end, i.e., the liquefaction plant, to reduce the gas pressure in a controlled manner. The investment cost for the pressure reduction system was set at 200,000 €, and for the compressor 500,000 €, proposed by Haimila (2015). For compression, the specific operating costs were set at 0.049 €/Nm^3, and for pressure reduction 0.015 €/Nm^3 (Haimila 2015).

The cost estimate does not include vehicle investments; the transportation service is purchased from a transportation company. The price for one ride was set at € 185. The input data used in the cost estimation for CBG transportation are summarized in Table 8.

Table 8. Input data for CBG transportation cost estimation.

Container capacity	Nm^3	7100
Specific cost for containers	€/Nm^3	60
Number of containers		5
Transportation price (per trip)	€	185
Number of trips		730
Compressor investment	€	500,000
Pressure reduction system investment	€	200,000
Specific cost for compression	€/Nm^3	0.049
Specific cost for pressure reduction	€/Nm^3	0.015
Maintenance cost (of total investment cost)	%	2

The annual cost estimate for CBG transportation is shown in Table 9.

Table 9. Breakdown of annual costs of CBG transportation. Time period 10 years.

Initial investment		
CBG containers	€	289 399
Compressor	€	67 934
Pressure reduction system	€	27 174
Total	€	384 506
Maintenance cost		
CBG containers	€	42 600
Compressor	€	10 000
Pressure reduction system	€	4 000
Total	€	56 600
Operating expenses		
Transportation	€	135 050
Compression	€	245 000
Pressure reduction	€	75 000
Total	€	455 050
Cost breakdown		
Investment cost	€	384 506
Operating and maintenance	€	511 650
Total costs	**€**	**896 156**

Compared to pipeline transmission, the initial investment in CBG transportation is significantly lower. However, high operating costs increase the overall cost. The high operating costs are explained by the actual transportation costs and the high gas compression costs.

It should be noted that the total cost of CBG transportation may differ noticeably from the estimate presented above. For example, as composite materials develop and become more widespread, the prices of CBG containers may fall from the average price estimate of 60 €/Nm^3 used in this work. For example, with a specific cost of 45 €/Nm^3 for containers, the annual total cost would fall to 813 k€/year. In addition, the initial investment would be lower if the existing equipment, such as compressors or CBG containers already in use in Ostrobothnia, could be utilized. However, the cost estimate made in this report included all different cost factors to give an overall picture of the cost structure.

Cost comparison

Figure 19 summarizes the cost estimates for pipeline and container transportation with different price scenarios.

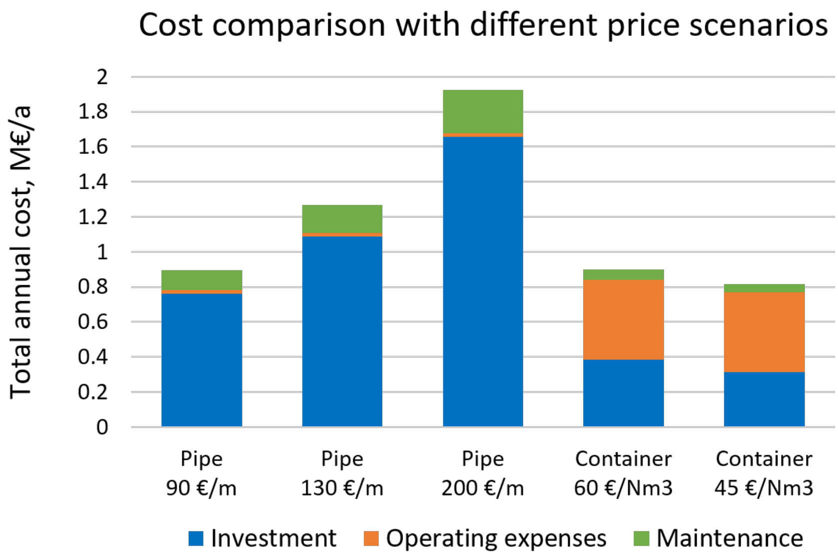


Figure 19. Pipeline and CBG transportation cost estimates with different price scenarios.

In general, the results from the cost comparison favored the cost-effectiveness of container transport over the pipeline investment. Pipe transmission proved to be cost-competitive only at a specific cost of 90 €/m. However, access to such low cost-level requires, i.e., an easy-to-install environment and well-suited soil throughout the design area. Even small environmental challenges can cause significant changes in unit costs.

Impact of investment length

The actual service life of a gas pipe is 30-40 years, and for composite cylinders up to 20 years. Therefore, cost breakdowns were also calculated for 20 years holding period. Specific costs and interest rate as in the base case. The results are collected in Table 10. As the investment life lengthens, the difference in annual costs narrows significantly due to the different cost structures of the alternatives studied.

Table 10. Cost breakdown with a 20-year period.

	Pipeline transmission	CBG transportation
Investment	0.697 M€	0.247 M€
Operating expenses	0.021 M€	0.455 M€
Service and maintenance	0.160 M€	0.057 M€
Total annual cost	**0.878 M€**	**0.759 M€**

Impact of gas volume

Despite the potentially higher costs, gas pipeline investment may be supported by the reliability of pipeline transmission and the long service life of the pipeline. The final choice of transportation method may also require consideration of other aspects, such as environmental impacts and future needs. A significant advantage of pipeline transmission is the ability to significantly increase capacity at a very low cost; when the gas volume is doubled to 100 GWh, only minor additional investment is required with pipeline transmission, as a larger amount of gas can be transported in the same pipeline by increasing the pressure in the pipeline; only the compressor capacity needs to be increased. In contrast, with CBG transportation, doubling the gas volume almost doubles the cost. Table 11 shows the annual costs with 100 GWh/year gas volume. As seen, as the gas volume increases, the pipeline investment becomes more cost-efficient.

Table 11. Cost breakdown with 100 GWh/year gas volume. Time period 10 years.

	Pipeline transmission	CBG transportation
Investment	1.114 M€	0.674 M€
Operating expenses	0.043 M€	0.910 M€
Service and maintenance	0.164 M€	0.099 M€
Total annual costs	**1.321 M€**	**1.683 M€**

In future scenarios, the possibility of utilizing biomethane pipeline in the development of the hydrogen economy is also noteworthy, as discussed in the following Section.

2.2.5 Utilization of biomethane network for hydrogen transmission

In Europe, hydrogen production and demand are expected to grow significantly in the coming decades. Hydrogen infrastructure development is expected to rely heavily on existing natural gas infrastructure as demand for natural gas declines and opens up new opportunities to exploit natural gas networks. (Wang et al. 2020). At the beginning of the energy transition, while hydrogen volumes are small, it makes sense to develop hydrogen economy and hydrogen supply by blending it with natural gas or biomethane. The Ostrobothnian gas pipeline could be part of this energy transition.

In general, implementing 5–15 % hydrogen by volume does not adversely influence end-user devices, public safety, or the durability and integrity of the existing natural gas pipeline network. However, the maximum hydrogen ratio can vary from case to case depending on, e.g., the composition of the natural gas and the type and age of the appliance or engine. Therefore, the impact of hydrogen blends on industrial facilities must be addressed on a case-by-case basis, and stationary gas engines likely will require changes to control systems. (Melaina et al. 2013.)

One consideration associated with hydrogen blending is the smaller size of the hydrogen molecule compared to the methane molecule, which increases the need for attention to the tightness of the seals and joints. However, although the permeation coefficient of hydrogen is higher through elastomeric sealing materials than through plastic pipe materials, pipes have much larger surface areas than seals, and leaks through plastic pipe walls would cause most of the gas losses (Melaina et al. 2013). Nevertheless, hydrogen permeation through plastic material is not considered a significant problem; e.g., Haines et al. (2003) predicted a gas leakage rate of 0.00005% with a 17% hydrogen blend.

Another important consideration regarding the hydrogen transmissions in pipelines is that the durability of some metal pipes can degrade when they are exposed to hydrogen over extended periods, particularly with hydrogen in high concentrations and at high pressures. The effect is highly dependent on the type of steel and must be assessed on a case-by-case basis. In contrast, there is no major concern about the hydrogen aging effect on PE plastic pipe materials. In addition, hydrogen blends can influence the accuracy of existing gas meters. The deviation of a gas meter with hydrogen blends varies depending on the meter design. In general, recalibration of existing meters is sufficient if the gas mixture contains less than 50 % hydrogen. The integrity management for distribution systems with hydrogen services will also require additional leak detection systems and more frequent inspections, increasing maintenance costs. (Melaina et al. 2013.)

Hydrogen has a lower energy density than methane: at the same pressure, a cubic meter of hydrogen contains one-third of the energy of a cubic meter of methane (Wang et al. 2020). The maximum biomethane transmission volume of the Ostrobothnian gas pipeline proposed in this work was about 100 GWh (at 8 bar), corresponding to 10 million Nm^3 of methane. With a mixing ratio of 20 %, the hydrogen transferred would be 2 million Nm^3. In that case, the amounts of energy transferred would be about 80 GWh of methane and 6 GWh of hydrogen.

At the design phase of the Ostrobothnian gas pipe, the prospect of mixing hydrogen should be considered and ensure the suitability of compressors, gas chromatographs, flow meters, and sealing materials for hydrogen-methane mixing. In the case studied in this paper, biomethane transported by the pipeline is intended for liquefaction, so hydrogen mixing would also require a gas separation system at the user end prior to liquefaction. Mature technologies for the separation of hydrogen and methane include pressure swing adsorption (PSA) and membrane separation.

2.2.6 Summary and conclusions

This work aimed to assess the feasibility and costs of a biomethane pipeline in Ostrobothnia. The study introduced a proposal for a 56 km long pipeline route between the two Ostrobothnian biogas plants. No obstacles or significant challenges to pipeline construction were identified on the proposed route, but a more detailed study of the terrain conditions is essential to refine the cost estimates.

The properties of the gas pipeline were examined with annual gas transmission volumes of 25–100 GWh. The final pipe dimensioning was based on the capacity of 50 MWh. A pipe with an inside diameter of 160 mm and a transmission pressure of 4 bar would be suitable for this biomethane transmission volume, and the pipeline capacity could be doubled simply by increasing the transmission pressure to 8 bar. At pressure levels below 8 bar, a low-cost PE plastic could be chosen as the pipe material.

In addition, a cost estimate was made for the construction and operation of the pipeline. The corresponding cost estimate was also done for CBG distribution by truck for comparison purposes. The cost analysis showed that the annual costs of the gas pipeline might be competitive to road transport in the case of easy installation environments, and with higher transmission volumes.

Despite the potentially higher costs, the gas pipeline investment may be supported by transmission reliability, the remarkably long service life, and the low and stable operating costs. An additional advantage of pipeline investment is the possibility to increase its capacity significantly at very low additional costs. The primary advantage of road transport is its flexibility to add and change routes.

Finally, an overview of the possibilities of utilizing the biomethane pipe network for hydrogen transmission was made. In general, implementing 5–15 % hydrogen by volume does not adversely influence end-user devices, safety, gas losses, or the durability and integrity of the existing methane pipeline network. At the design stage of a potential gas pipeline in Ostrobothnia, the prospect of mixing hydrogen should be considered and ensure the suitability of compressors, gas flow meters, sealing materials, etc., for hydrogen-methane mixing. Depending on the end-use, a gas separation system may also be needed.

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3 ENVIRONMENTAL IMPACT ASSESSMENT OF BIOGAS USE IN PUBLIC TRANSPORTATION

Kirsi Spoof-Tuomi

The main objective of WP2 was to investigate CH_4 and other gaseous emissions of a biogas-fueled urban bus in real-world conditions. This report describes the main findings of the study. The detailed research methods, calculation procedures, and complete research results are presented in the article: Spoof-Tuomi, K.; Arvidsson, H.; Nilsson, O.; Niemi, S. Real-Driving Emissions of an Aging Biogas-Fueled City Bus. *Clean Technol.* 2022, 4, 954–971. https://doi.org/10.3390/cleantechnol4040059.

The actual driving emissions were recorded using a Portable Emissions Measurement System (PEMS). The key advantage of on-board measurements is that they can truly reflect the emission characteristics of vehicles under a wide range of traffic conditions and operating cycles (e.g., stop-and-go driving with frequent accelerations and deceleration events and long idle times) and ambient conditions, including those that are otherwise difficult to replicate in the laboratory, such as large road gradients (Franco et al. 2013).

PEMS measurements were performed in real traffic conditions on a regular bus line in Vaasa, a collaboration of the University of Vaasa with RISE Research Institutes of Sweden. In addition to methane emissions, gaseous emissions of NO_x, CO, and CO_2 were measured. We conducted two measurement campaigns, the first in March 2022 and the second in June 2022. In addition, the total carbon footprint of compressed biogas (CBG) is discussed in terms of its Greenhouse Gas (GHG) reduction potential, defined as the percentage reduction in life cycle GHG emissions relative to its fossil counterpart natural gas and traditional diesel fuel.

3.1 Material and methods

3.1.1 Test vehicle

Exhaust emission tests in real driving conditions were carried out on a Scania Euro VI bus owned by the City of Vaasa and operated by WasaCitybus. The CBG-fueled bus was equipped with a spark ignition engine with a displacement of 9.3 dm^3 and a power of 206 kW. The vehicle was equipped with exhaust gas recirculation (EGR) and a three-way catalytic converter (TWC) after-treatment system. The model year of the bus was 2016, and the accumulated mileage in Test 1 was 375 000 km, and in Test 2, 400 000 km.

3.1.2 Portable emissions measurement system

The real driving gaseous emissions of CH_4, CO, CO_2, NO and NO_2 from the tested city bus were measured and recorded using an on-board VARIOplus Industrial device manufactured by MRU. VARIOplus measures CH_4, CO, and CO_2 concentrations using a non-dispersive infrared (NDIR) sensor, and NO_x concentrations are measured using electrochemical cells.

The engine operational data (engine speed, engine torque, engine coolant temperature, air flow, lambda, and vehicle speed) were recorded from the vehicle engine control unit (ECU) via an onboard diagnostics (OBD) system using Scania Diagnosis & Programmer (SDP3) software. The vehicle's position in terms of latitude, longitude and altitude, and the vehicle speed data were registered using an external global positioning system (GPS). A dedicated weather station was used to register ambient conditions (temperature, pressure, and relative humidity). The real-world emission data obtained with PEMS and the GPS and weather data were collected and stored with DEWESoft data acquisition system. All data were recorded with a frequency of 1 Hz.

The electrical power to the PEMS system was supplied by an external power supply unit. The system set-up is presented in Figure 20.

Figure 20. Measurement system set-up.

3.1.3 Test route

Emission measurements were performed in real driving conditions on an urban route in Vaasa, i.e., in normal traffic and with normal driving patterns and typical passenger loads. The selected test route was the same route the bus usually travels daily. Fig. 21 shows the driving circuit chosen for the tests. The length of one circuit was 25.5 km, and the same circuit was run three times. The total test duration was approx. 3 hours. The route included both urban and rural driving. Table 12 shows the percentages and mean velocities for three different driving speed ranges. A detailed speed profile of one driving circuit is shown in Fig. 22. The passenger load varied between 5 and 30 percent during the tests.

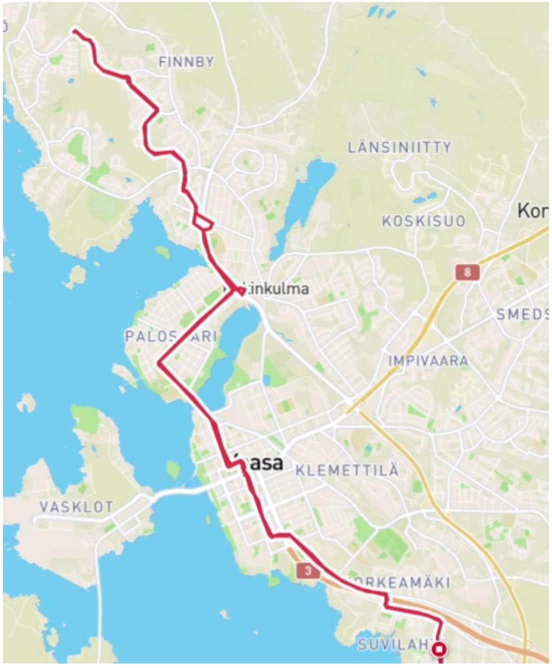

Figure 21. Driving circuit.

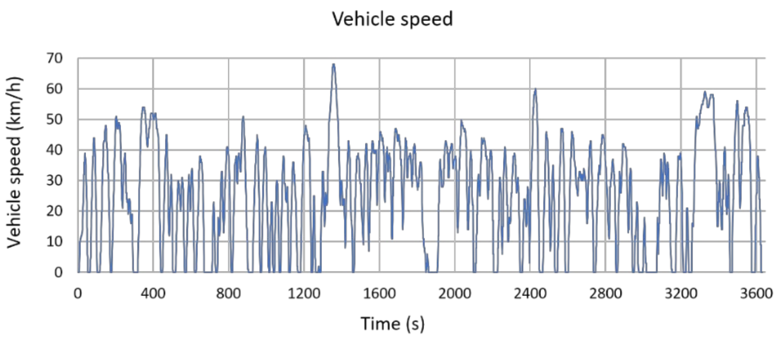

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Figure 22. Speed profile of the driving circuit.

Table 12. Shares of driving speed ranges.

	Speed range	Time (min)	%	Mean velocity
Urban driving	0-30 km/h	102	56	12
Urban driving	30-50 km/h	65	36	38
Rural driving	50-75 km/h	16	9	57
Total		182		25

3.1.4 Ambient conditions

The first measurement campaign was performed in March 2022, and the second in June 2022. Table 13 summarizes the average ambient conditions during the tests.

Table 13. Ambient conditions during the tests.

Ambient conditions	Test 1	Test 2
	March 2022	June 2022
Temperature (°C)	-5 °C	+18 °C
Pressure (kPa)	102.5	100.5
Humidity (%)	65.5	54.7

3.1.5 Fuel

The fuel used in the test was CBG from a commercial filling station. The methane content of the fuel was 97 % by volume. The other main components of the fuel were CO_2 (2.2 vol.-%), nitrogen (0.5 vol.-%) and oxygen (0.3 vol.-%), so the energy content of the fuel was solely related to the methane concentration. The calculated lower heating value (LHV) of the gas was 46.4 MJ/kg.

3.2 Results and discussion

3.2.1 Gaseous emissions

In the current legislation, the regulatory in-service conformity (ISC) emission test applies the 20 % power threshold as a boundary condition for Euro VI-C bus engines. However, Mendoza Villafuerte et al. (2017) showed that a large fraction of urban operation is not considered if the current power threshold boundary for post-processing the PEMS data is applied, and up to 80 % of the data may be excluded from the emission analysis. To give a more accurate depiction of real-driving emissions, no power threshold boundaries were applied in this study.

Emissions were recorded from the moment the coolant temperature had reached 70 °C for the first time or stabilized within ±2 °C over a period of 5 minutes, whichever came first (EU 582/2011). Specific emissions were calculated in both g/kWh and g/km, and the results are presented separately for the total trip and for urban and rural sections of the circuit (Fig. 23). Although the tests performed did not fully reflect the ISC tests in the type approval procedure regarding boundary conditions and route requirements, the Euro VI standard limits (ISC limit) are also presented for comparative purposes.

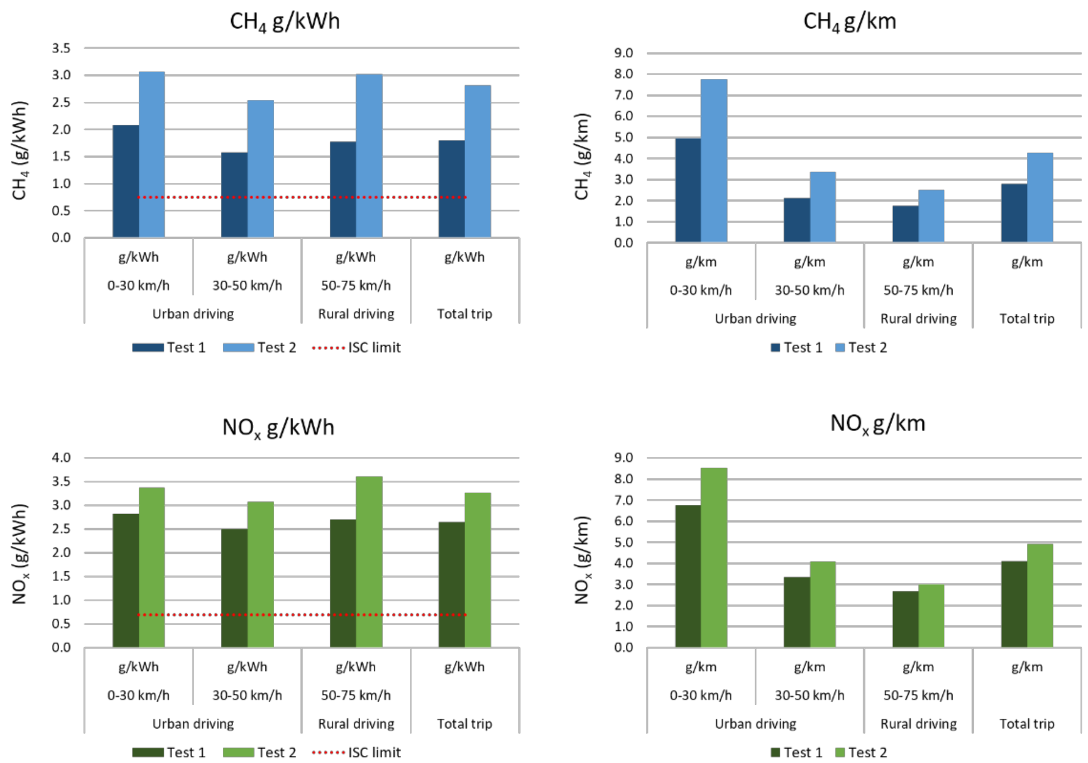

Figure 23. Specific CH_4 and NO_x emissions in g/kWh and g/km. Dotted lines indicate the Euro VI standard limits.

CO emission values were low and well below the ISC limit of 6 g/kWh in both tests, indicating efficient oxidation of CO in the catalyst. In contrast, relatively high values were observed for CH_4 and NO_x, indicating impaired CH_4 oxidation and NO_x reduction in the catalyst after its service life of 375,000 km (Test 1). After 400,000 km (Test 2), the catalyst efficiency had further deteriorated. Here, it should be noted that according to EU Regulation (EC 595/2009), the minimum mileage or time after which the engine is still expected to comply with applicable emission limits for category M3 buses is 300,000 km or six years, whichever comes first. Hence, the required “emission durability” period had already been exceeded in our case.

The primary reason for relatively high CH_4 and NO_x emissions after TWC was assumed to be the low CH_4 reactivity due to a partial deactivation of the catalyst. In addition to the low CH_4 oxidation rate, low CH_4 reactivity also means that methane-based reducing agents for NO_x reduction do not work, leading to substantial NO_x breakthrough from the catalyst, also concluded by Van den Brink & McDonald (1995).

One of the most important reasons for the deactivation of TWC in automotive applications is chemical deactivation (Matam et al. 2012), caused by lubricating oil additives and other impurities in the exhaust gases. For example, Winkler et al. (2008) observed a significant increase in hydrocarbon emissions during CNG operation over a short TWC lifetime of 35,000 km. Contaminants originating from the lubricating oil, such as calcium, phosphorus, and magnesium, detected on the catalyst's surface, appeared to affect especially CH_4 oxidation. In addition to lubricating oil, another source of catalyst poisons is the impurities in the fuel. The CBG used in this study contained small traces of commonly encountered catalyst poison sulfur (S) (< 2.3 mg/Nm^3) and siloxanes (0.7 mg/Nm^3). Although the amounts of these compounds were very low, they could have had a deactivating effect on the emissions control system.

Furthermore, the light-off of a TWC in gas-fueled engine exhaust typically occurs at higher temperatures compared to gasoline engines (Jääskeläinen 2017). Indeed, methane is the most difficult hydrocarbon to oxidize due to its high stability (Stoian et al. 2021). A typical light-off temperature for methane is 400 °C (Stoian et al. 2021), but in a deactivated catalyst, significantly higher temperatures, up to 500–600 °C (Auvinen et al. 2021), may be required to break the strong C-H bonds in methane. At low loads (Fig. 24), common in a city bus's driving profile, the exhaust gas temperature was too low to allow the deactivated catalyst to work effectively.

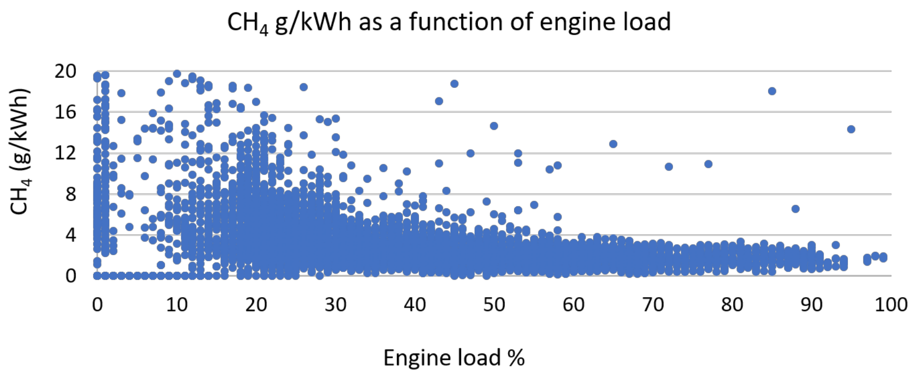

Figure 24. Specific CH_4 emissions as a function of engine load % in Test 2.

Thus, restoring the catalytic activity of a deactivated TWC is a critical consideration. In some cases, depending on the adsorbed poison, the activity of the poisoned catalyst can be at least partially restored by regeneration (Lassi 2003). For example, SO_2 can be removed from the catalyst under elevated temperatures and anoxic or very rich conditions, as shown by Auvinen et al. (2021). Careful control of the exhaust gas composition during regeneration could provide significant benefits in terms of CH_4 emissions. However, under real driving conditions, the rapidly and dramatically varying exhaust gas temperature and composition between oxidizing and reducing environment (Fig. 25) make the onboard regeneration difficult to control.

Another possible deactivation mechanism for TWC is thermal degradation. Three-way catalysts are known to lose their activity when exposed to high temperature (> 800 °C) oxidizing environments, typically occurring during fuel shut-off phases (Zheng et al. 2015). Switching off the fuel flow, e.g., during engine braking is a strategy of the automotive industry to improve fuel economy. Thermal degradation is critical to the catalyst's performance since these changes are typically irreversible.

In addition to the partial deactivation of the catalyst, another probable reason for the relatively high emissions was the fluctuating lambda value (Fig. 25). Indeed, close control of the exhaust gas composition is essential for high emission conversion as the composition of the gas entering the TWC significantly affects its catalytic efficiency. For simultaneous conversion of HC, CO, and NO_x species in the TWC, the engine must be operated within a very narrow air-fuel ratio (AFR) window – near stoichiometric conditions – due to a rapid drop in NO_x conversion efficiency on the lean side and a non-complete conversion of hydrocarbons both in lean and in rich of stoichiometry (Di Maio et al. 2019)]. The narrow AFR range over which significant conversion of natural gas exhaust emissions is possible presents a challenging control problem. As seen in Fig. 25, lambda was outside the optimal range for a significant part of the time in our experiments.

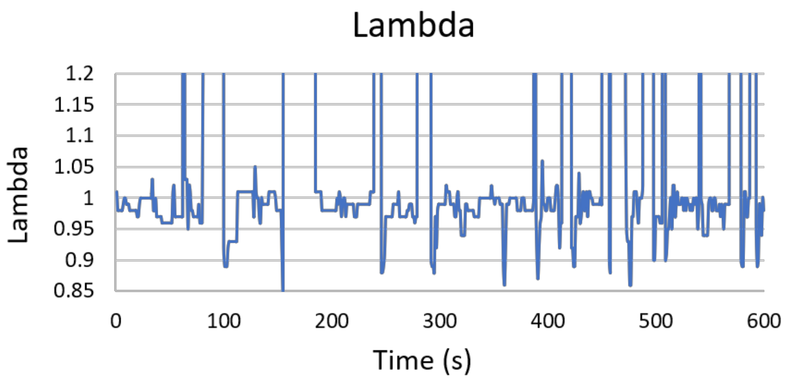

Figure 25. Fluctuating lambda values under real driving conditions.

In sum, deterioration of the exhaust after-treatment systems over time should be monitored as they are exposed to different aging processes resulting in elevated real-world emissions. Our results indicate a catalyst replacement need after 375,000 km of service life. In addition, precise lambda control is necessary to ensure high conversion rates throughout the vehicle's lifetime.

3.2.2 Fuel consumption

The total fuel consumption in Test 1 at -5 °C was 21.9 MJ/km (6.1 kWh/km), corresponding to 0.306 kg/kWh and 47.1 kg/100 km. In June, at +18 °C, the vehicle showed better fuel economy with fuel consumption of 19.8 MJ/km (5.5 kWh/km), corresponding to 0.283 kg/kWh and 42.7 kg/100 km (Fig. 26).

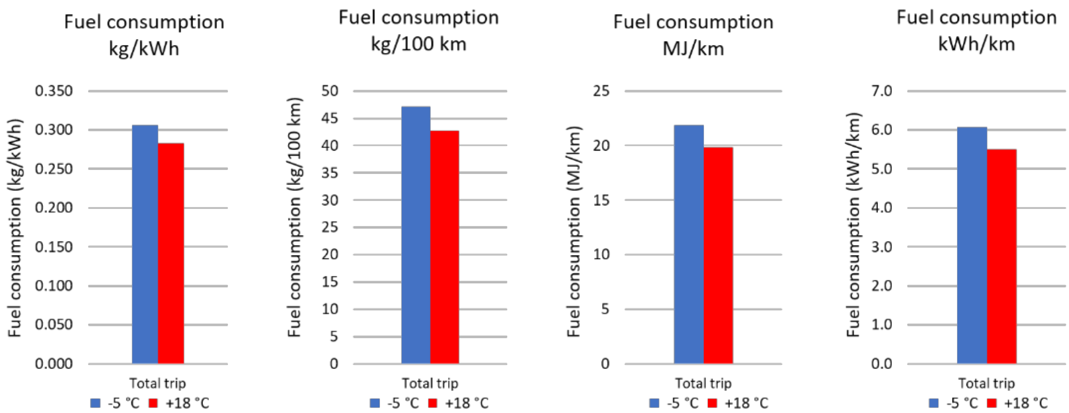

Figure 26. Fuel consumption at -5 °C and +18 °C.

3.2.3 Well-to-wheels analysis

In the transport sector, well-to-wheels (WTW) analysis is a commonly used method for assessing the carbon intensity of a fuel. Carbon intensity refers to the amount of greenhouse gases – including CO_2, nitrous oxide, and methane – released during the production and consumption of a transportation fuel, measured in grams of carbon dioxide equivalent per megajoule of energy (g CO_2-eq./MJ).

Biogas production process

The life cycle steps for CBG investigated in this study are feedstock collection and transportation, biogas production, biogas processing to biomethane, biomethane compression, and finally, combustion in an engine. The CBG was produced at Stormossen waste treatment plant near Vaasa. The anaerobic digestion process at Stormossen is divided into two separate process lines. Biogas reactor 1 is fed with wastewater sludge, and the raw material used in biogas reactor 2 is municipal biowaste, supplied within a radius of 40 km.

In 2020, raw biogas production at Stormossen was 2.7 million Nm^3, of which 52 % was upgraded into biomethane, 32 % was used for heat and electricity production, and the rest was flared. The methane content of the raw biogas was 62 %. (Stormossen 2020.) The biogas upgrading is done by an amine scrubber. The main advantages of chemical absorption with amine solvents are a high methane recovery rate in the upgraded biogas and a low methane slip of < 0.1% (TUV 2012). After the refining stage, biogas contains 97–98 % methane. Finally, the processed biomethane is piped to a gas filling station near the biogas plant. At the refueling station, the gas is pressurized to 300 bar and stored in gas cylinders.

Although the combustion of waste-based biomethane is considered carbon-neutral in Finland's national GHG inventories (CO_2 emissions from biogas combustion are reported as zero) (StatFin 2021), the use of biomethane may still have climate impact from the above-mentioned earlier stages of the fuel chain. For CBG production, the major contributors of GHG emissions are energy consumption and fugitive losses of methane during digestion and upgrading processes (Uusitalo et al. 2014). In addition, some GHG emissions form during the collection of wastes and residues.

Life-cycle GHG inventory

In this study, the calculation of GHG emissions begins with feedstock collection and transportation. GHG emissions from these steps are based on the following assumptions: Transportation distance 40 km and diesel B7 fuel consumption 20 l/100 km. The lower calorific value of diesel B7 fuel is 43 MJ/kg. The well-to-tank emission factor for diesel B7 was 14.7 g CO_2-eq./MJ fuel, based on the JRC (2014) data. Tank-to-wheels CO_2 emission factor for diesel B7 was set at 68.4 g CO_2-eq./MJ fuel (StatFin 2021). The heat and electricity needs of biogas production and upgrading processes are covered internally by the plant's own CHP biogas engine and were therefore ignored in the GHG inventory. Methane emissions were calculated assuming a methane loss of 1 % during anaerobic digestion (Majer et al. 2016) and 0.1 % during the upgrading process (Ardolino et al. 2021). Methane emissions were converted to CO_2-equivalents using a 100-year time horizon global warming potential (GWP) factor of 28 (Myhre et al. 2013). The energy demand for biomethane compression to 300 bar is 0.25 kWh/Nm^3 (Bauer et al. 2013), and the electric energy for compression is taken from the public grid. The CO_2 emission factor for electricity generation in Finland in 2020 was 68.6 g CO_2-eq./kWh (EEA 2021). Table 14 summarizes the main assumptions and input data used in the calculation.

Table 14. CBG well-to-tank (WTT) GHG emissions.

Parameter	Value	Unit	g CH_4 /$MJ_{bio\text{-}CH4}$	g CO_2-eq. /$MJ_{bio\text{-}CH4}$	Source
Feedstock collection and transportation					
Diesel trucks (Diesel B7 fuel)	40	km		1.95	JRC 2014; StatFin 2021
Biogas production and refining					
Total biogas production	2 716 000	Nm^3			Stormossen 2020
52 % of raw gas for upgrading	1 412 320	Nm^3			Stormossen 2020
Methane content (62 %)	875 638	Nm^3			Stormossen 2020
Total biomethane production	31 522 982	MJ			
Heat demand*					
- Anaerobic digestion	0.19	kWh/$Nm^3_{raw\ gas}$			Majer et al. 2016
- Upgrading	0.110	kWh/$kWh_{bio\text{-}CH4}$			
Electricity demand*					
- Anaerobic digestion	0.14	kWh/$Nm^3_{raw\ gas}$			Majer et al. 2016
- Upgrading	0.0136	kWh/$kWh_{bio\text{-}CH4}$			
Methane losses					
- Anaerobic digestion, 1%	6 368	kg	0.202	5.66	Majer et al. 2016
- Upgrading, 0.1 %	630	kg	0.020	0.56	Ardolino et al. 2021
Compression					
Electricity demand	0.25	kWh/Nm^3		0.48	Bauer et al. 2013, EEA 2021
WTT GHG emissions				**8.65**	

* Covered internally by the plant's own CHP biogas engine

The GHG benefits associated with transition from fossil-based natural gas or diesel to biomethane were calculated by comparing well-to-wheels (WTW) CO_2-eq. emissions, see Table 15. Well-to-tank GHG emission factors for compressed natural gas and diesel fuel were taken from JRC (2014). Tank-to-wheel GHG emissions for gas buses are based on the CO_2 and CH_4 emission results recorded in this study, but CO_2 emissions are considered only for fossil compressed natural gas (CNG). Tank-to-wheels CO_2 emission factor for diesel buses was taken from (StatFin 2021). The average fuel consumption from Test 1 and 2 in this study was 20.8 MJ/km, and this value is applied to both CBG and CNG bus. It is well known that compression-ignition diesel engines have higher thermal efficiency compared to spark ignition gas engines. Therefore, the fuel consumption of a diesel bus was set at 80 % of that of a gas bus, based on the VTT's (Technical Research Centre of Finland) comprehensive report on city bus emissions measurements (Söderena et al. 2019).

Table 15. Well-to-wheels CO_2-eq. emissions for CBG, CNG and Diesel B7.

	CBG	CNG	Diesel B7
GHG-emissions			
Well-to-tank (g/MJ_{fuel})	8.65	13.0	14.7
Tank-to-wheels			
• CO_2 (g/MJ_{fuel})		46.6	68.4
• CH_4 (g/MJ_{fuel})	0.1708	0.1708	
Total GHG (g $CO_{2\text{-}eq}$/MJ_{fuel})	13.4	64.4	83.1
Fuel consumption (MJ/km)	20.8	20.8	16.7
Specific GHG (g $CO_{2\text{-}eq.}$/km)	**279**	**1342**	**1385**

Figure 27 shows the percentage changes in life-cycle GHGs for the studied fuels. Shifting from conventional diesel to fossil natural gas does not show meaningful GHG benefits, bearing in mind the higher thermal efficiency of compression-ignition engines compared to spark-ignition gas engines. However, for biomethane, the situation is very different; 80 % GHG emission benefit is achieved by switching from diesel to biomethane. With more precise methane emission control, GHG emission savings would advance towards 90 %.

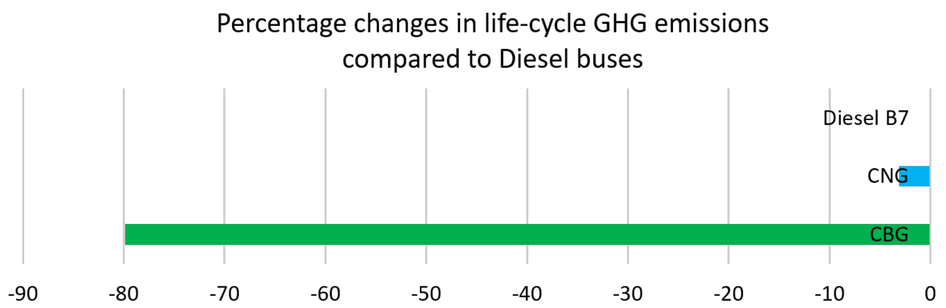

Figure 27. Percentage changes in life-cycle GHGs.

This gives a strong environmental argument for biogas use. Increasing biogas use would be a quick and cost-effective way to reduce GHG emissions from urban traffic. Unfortunately, the potential of renewable gas is not acknowledged in the current EU emission standards, which only focus on tank-to-wheels emissions. Changing the measurement method to life-cycle-based (WTW) instead of tailpipe measurement would enable a proper assessment of GHG emissions of future vehicle technology and fuel combinations. However, the results of this study can be utilized in designing strategies for transitioning to sustainable urban transport systems.

3.3 Summary and conclusions

Transition to low emission transportation and cleaner cities requires a broad introduction of low- and zero-carbon alternatives to conventional petrol- and diesel-powered vehicles.

This paper presents the results of real driving emission measurements from a Euro VI biogas-powered city bus equipped with a TWC. In addition, the total carbon intensity of CBG was investigated and compared to its fossil counterpart CNG and traditional diesel fuel.

The main findings were, first for the bus:

- The rapid changes in exhaust gas temperature and composition under transient driving conditions seemed to be a critical challenge to an efficient operation of the TWC.
- Unimpressive CH_4 oxidation and NO_x reduction were observed in the catalyst after its service life of 375,000 km–400,000 km. In contrast, CO emissions were low, indicating efficient oxidation of CO in the catalyst.
- The primary reason for deficient CH_4 and NO_x conversion over TWC was assumed to be the low CH_4 reactivity due to a partial deactivation of the catalyst. At low loads, common in a city bus's driving profile, the exhaust gas temperature was too low to allow efficient CH_4 oxidation. In addition to the low CH_4 oxidation rate, low CH_4 reactivity also means that methane-based reducing agents for NO_x reduction do not work, leading to substantial NO_x breakthrough from the catalyst.
- Based on the above, deterioration of the exhaust after-treatment systems over time should be monitored as they are exposed to different aging processes resulting in elevated real-world emissions.
- Another critical issue was the fluctuating air-to-fuel ratio. Lambda was outside the optimal range for a significant part of the time, likely reducing the TWC efficiency. This highlights the need for precise lambda control to ensure high conversion rates throughout the vehicle's lifetime.

Additionally,

- The WTW analysis showed an 80 % GHG emission benefit by switching from diesel to biomethane, giving a strong environmental argument for biogas use. With more precise methane emission control, GHG emission savings would advance towards 90 %.

The presented real-driving emission results are of great importance in supplementing the emission data for aging gas-powered heavy-duty vehicles, filling the gap of data on emissions closer to the service life of the vehicles. After all, the average age of bus fleets in Finland, for example, is over 12 years. The results of this study can also be utilized in scheduling catalyst maintenance or replacement activities.

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4 BIOGAS UTILIZATION OPPORTUNITIES IN DIFFERENT CONTEXTS: INDUSTRY, WASTE-TO-ENERGY SECTOR, AND GREENHOUSES.

Kirsi Spoof-Tuomi and Carolin Nuortila

Achieving national and international carbon neutrality targets requires industry to adopt sustainable energy solutions based on renewable energy sources. Although the use of industrial fuels in Finland has long shown a structural shift from fossil fuels to renewable fuels, in 2019 fossil fuels still accounted for about a quarter of the fuels used by the industry sector (StatFin 2021a).

Biogas offers a viable alternative for industrial operators to meet their emission targets. Purified and upgraded biogas - biomethane - has the same properties as natural gas: the energy density is high, and it is free of sulfur or heavy metals. In addition to natural gas, biomethane can replace other fossil gases such as propane and butane, as well as fuel oils. Alongside the substantial greenhouse gas savings, replacing oil-based fuels with renewable biomethane will reduce emissions of sulfur, particulate matter, and nitrogen oxides.

This study examined the possibilities for industrial companies to switch to renewable biogas in their operations. Regionally, the study was limited to the Ostrobothnia region. As the integration of biomethane into industrial energy systems requires a stable and predictable operating environment and assurance of the continued availability of biomethane, the biomethane volumes available in Ostrobothnia today and in the near future were investigated. In addition, a comprehensive survey of the current industrial fuel prices was done. The price forecasts with different scenarios until 2040 were conducted as well. In the case study, industrial research and testing activities, vital in the region, was selected as potential biogas user.

Another potential new biomethane user investigated in this study was the waste-to-energy sector. To ensure the efficient combustion of waste, waste incinerators must maintain sufficiently high temperatures in all conditions. If necessary, the temperature is raised to the appropriate combustion temperature by burning auxiliary fuel. The most used auxiliary fuel in waste-to-energy plants operating in Finland is fossil fuel oil, and two plants use natural gas as an auxiliary heat source. The study aimed to investigate the possibilities of replacing fossil fuels used as auxiliary fuels in the waste-to-energy sector with renewable biogas. The Westenergy waste-to-energy plant, currently using light fuel oil as an auxiliary fuel, was selected for the case study. From a technical perspective, various storage options and modification needs related to burner technology were reviewed. From an economic point of view, the investment costs of different gas storage options and the costs of technical modifications were analyzed. The GHG emission benefits of fuel switching were also assessed.

Ostrobothnia has traditionally been a region in Finland with many greenhouse companies which are particularly aggregated in the southern parts of the region. It was therefore of interest to investigate whether the greenhouse industry could be part of a circular economy with biogas, both contributing to biogas production through waste plant material and potentially also to act as a biogas consumer.

4.1 Gaseous fuels for industrial and energy use

Technically, gas is an ideal fuel for energy production. A significant advantage of gas-based energy production is its rapid adjustability to fluctuating demand. Gas-fired power plants are ideal for balancing power generation for power systems with high levels of intermittent energy sources such as solar and wind, as they only take minutes to start and adjust. Like natural gas, biogas can also be used as a source of peak power that can be rapidly ramped up.

Gas can also be used as an energy source in many industrial processes. Gas is an ideal fuel, especially in situations where high temperatures and quick adjustability are required. The most significant industrial users of natural gas in Finland are found in the chemical and forest industries. In metal processing, gas is suitable for many steps, from smelting to hardening. Other industrial applications ideal for gas can be found, e.g., in the food industry, clay, glass and concrete industry, laundries, powder coating plants, etc. In industrial processes, biomethane can be used for all the same purposes as natural gas to bring significant environmental and climate benefits.

4.2 Biomethane availability

In regions where natural gas grids already exist, there is a system suitable for the distribution of biomethane as well. However, the pipeline network built in Finland for natural gas distribution covers only the southeast and the southern part of the country. To utilize biomethane outside the national gas grid, like in Ostrobothnia, the options for its transportation are 1) compression into a gas transportation container (CBG, compressed biogas) and 2) liquefaction (LBG, liquefied biogas, also known as liquefied biomethane LBM, and bio-LNG) . In the case of short distances, transportation by a low-pressure gas distribution pipeline may also be a viable option.

In Ostrobothnia, biomethane for industrial use is produced by Jeppo Biogas Ab and Ab Stormossen Oy. Today, Jeppo Biogas' annual biogas production is 30 GWh (Jeppo Biogas 2021). Some of the gas is upgraded, pressurized, and transported to customers in high-pressure gas containers. According to the environmental license, the plant's capacity can be further increased. The company's vision is to further process biomethane into liquid form in the future. Stormossen's gas production in 2020 was about 16 GWh, of which about half was used to produce transport fuel, and a half was used in its own processes or flared (Stormossen 2021).

The advantage of liquefied methane is its higher energy density and more efficient transport compared to compressed gas. The development of the LNG distribution network has also opened new opportunities for liquefied biogas, as the same distribution chain is suitable for the distribution of LBG. LBG is also fully miscible with LNG; they can be mixed in any desired mixing ratio and used simultaneously or alternately in the same application. The compatibility of LNG and LBG also ensures the availability of fuel in all situations; security of supply during possible LBG distribution interruptions can be implemented safely and flexibly with LNG.

Liquefied biomethane has been available in Finland since the end of 2020. Gasum's biogas plant in Topinoja, Turku, produces about 60 GWh of liquefied biomethane per year for heavy transportation, industry, and maritime sector. LBG deliveries to industrial facilities in Ostrobothnia could be carried out by tanker trucks from Turku. In the near future, it is also possible to distribute LBG through the Gasum customer terminal to be built in Vaskiluoto, Vaasa.

Interest in liquefied biomethane is growing, and there are several LBG projects underway in Finland. For example, the Nurmo Bioenergy biogas plant, planned to be built in Southern Ostrobothnia, will have a total capacity of 100 GWh of methane per year. Some of the biogas produced is used to produce heat and electricity (CHP), and some is upgraded and pressurized or liquefied. The plant has already received the environmental license and the building permit. A new biogas plant with liquefaction facilities is also planned in Oulu Laanila. When completed, the plant will produce 40 GWh of LBG per year. In addition, after the expansion of the Oulu Rusko biogas plant, 20 GWh of biomethane per year will be transported from Rusko for liquefaction in Laanila. The annual production volume of liquefied biogas in the Oulu region would then be a total of 60 GWh. After completing the above projects, the Finnish LBG production will triple from the current level.

4.3 Industrial fuel prices and long-term price projections

The report underlying the text for this chapter had been finalized in December 2021 (Spoof-Tuomi 2021), before the geopolitical developments took place in February 2022 in Europe that added profoundly to instability of the world energy pricing. The reader is encouraged to keep this in mind while reading this chapter.

4.3.1 Current fuel prices

In Europe, LNG price is generally tied to the Dutch Title Transfer Facility (TTF) gas price. Figure 28 shows the TTF price history over the last 12 months. The natural gas price remained stable and low at 15–20 €/MWh level until the spring of 2021, when the price began to rise. In summer, and especially in the third quarter of 2021, the TTF gas price continued its sharp increase, rising to 85 €/MWh by the end of September, and rose to a record level of 116 €/MWh at the beginning of October. In November 2021, TTF prices fluctuated between 65 and 95 €/MWh.

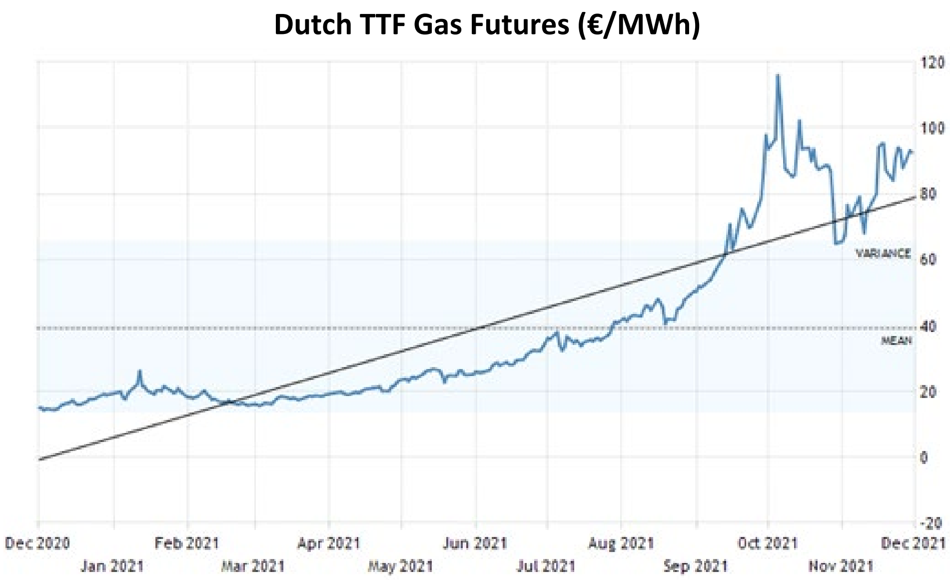

Figure 28. TTF index development in 2021 (Trading Economics 2022a).

The steep rise in European gas prices has been driven by falling gas storage levels in continental Europe due to the cold and long heating season in Europe last winter and the sharp increase in energy demand. The price of European gas has also been affected by the high demand for liquefied natural gas in the Asian market, which has led to the rerouting of LNG ships originally destined for European LNG import terminals to the Asian market. In addition, the European gas price has been shaken by uncertainties about the new Nord Stream 2 pipe commissioning schedule (Suomen Kaasuenergia 2021).

The gas market has been very volatile in recent months, so it is not easy to estimate LNG prices in 2022. If the factors that have raised the gas price develop in a favorable direction, relief in the price level can be obtained quickly. For example, Argus Media forecasts that the TTF index will fall sharply after spring 2022 and settle at 40 €/MWh in summer 2022. A similar assessment is presented by the International Monetary Fund (IMF 2021). On the other hand, Trading Economics, for example, forecasts that the price of European gas will remain high at 60 €/MWh until the end of 2022 (Trading Economics 2022a).

The price comparison in Figure 29 shows the LNG, LBG, propane, and light fuel oil prices for industrial customers in 2021. All prices are without VAT. Due to the recent intensive fluctuation of fossil fuel prices, the average 12-month prices are presented. For natural gas, the average 12-month TTF index price is 40 €/MWh. In Finland, LNG's purchase price to the customer consists of the wholesale price, excise duty of 23.35 €/MWh, and gas supply chain costs. For example, Heinonen (2016) estimated distribution costs to be around 7 €/MWh. Thus, the final price for LNG presented here is 70 €/MWh.

The LBG price is 87 €/MWh, consisting of the production cost of upgraded biomethane 65 €/MWh (IEA 2020), the liquefaction costs of 15 €/MWh (Spoof-Tuomi 2020) and distribution costs of 7 €/MWh. The LBG price does not include excise duty, as the Finnish Excise Duty Act did not cover biogas when preparing this report. However, the reform of biogas taxation is currently underway at the Ministry of Finance.

The high natural gas prices in autumn 2021 have increased the demand for liquefied petroleum gas (LPG), which has also been reflected in LPG prices. The CIF ARA (Amsterdam-Rotterdam-Antwerp) futures for propane in November 2021 were 695 €/ton. In December 2020, CIF ARA for propane was 330 €/ton (Barchart 2021). The 12-months average price, shown in Fig. 29, for propane is 512 €/ton, corresponding to 40 €/MWh. The excise duty on propane is € 24.60 €/MWh, and the distribution cost was estimated at 6 €/MWh.

In 2021, the Brent crude oil price fluctuated between 51–85 USD/barrel. In Figure 29, the 12-month average of 68 USD/barrel (Trading Economics 2022b), corresponding to 38 €/MWh, was used. The excise duty on light fuel oil is 27.58 €/MWh, and the production and distribution costs were set to 12 €/MWh, resulting in a total price of approximately 78 €/MWh.

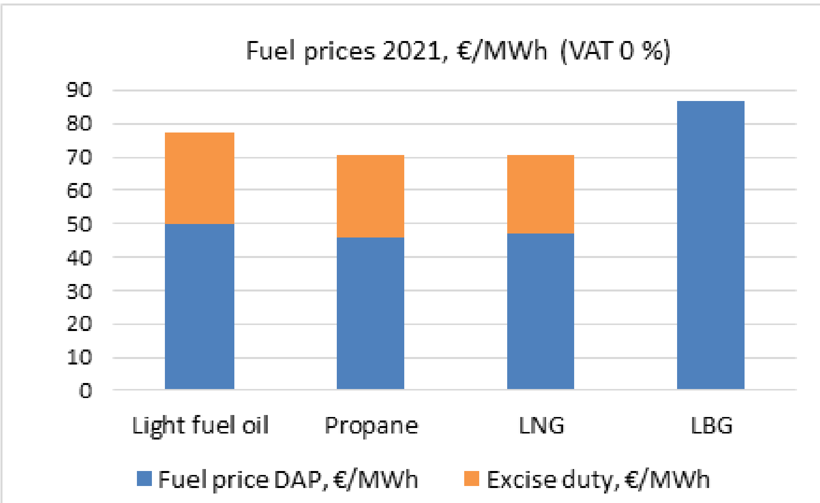

Figure 29. Industrial fuel prices 2021, 12-month average.

4.3.2 Long-term price scenarios

Fuel costs are sensitive to global market price fluctuations. Therefore, selecting an energy source for industrial use calls for a review of fuel price forecasts well into the future. In this chapter, four different scenarios are presented.

Uncertainties about the future crude oil price is a concern. The development of crude oil prices affects both the fuel oil and propane, a by-product of oil refining, prices. The price of crude oil has fluctuated sharply in recent years. For example, in April 2020, the very rapid collapse in demand caused by the corona pandemic lowered the oil price to about 20 USD/barrel, pushing oil production down to balance supply and demand. In 2021, oil demand increased rapidly, and production could not be started at the pace of demand growth, leading to a sharp rise in crude oil prices. The crisis in natural gas prices has also boosted the demand for petroleum products. In October 2021, the cost of Brent-grade crude oil reached 85 USD/barrel. At the end of November, the price increase reversed, leading to a 70 USD/barrel price level at the beginning of December 2021 (Trading Economics 2022b).

Predicting crude oil prices for the next 12-18 months is tricky; according to some estimates, the price could rise to over 100 USD/barrel in the coming months. However, according to IMF forecasts, the Brent crude oil price is expected to return to the 2019 level of 64 USD/barrel in 2022. This article uses the IMF 2022 estimate as a starting value for the crude oil price development scenarios. The long-term crude oil price development scenario presented in this report is based on the EIA (U.S. Energy Information Administration) forecast shown in Figure 30. By 2030, global demand is expected to raise the real price of Brent-grade oil by 46 percent compared to 2022. By 2035, EIA predicts a 60 percent increase, and by 2040, a 75 percent price increase compared to 2022. (EIA 2021.)

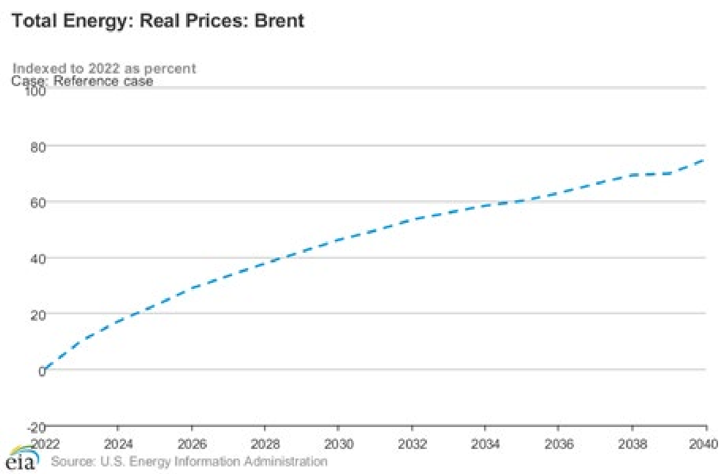

Figure 30. Predicted percentage increase in real prices of Brent crude oil 2022–2040 (EIA 2021).

The long-term price development scenario for propane is expected to follow the price trend of crude oil. In the price development scenarios for propane, the starting value for 2022 is the average of the European Propane CIF ARA futures for 2022 472 €/ton (CME 2021), corresponding to 37 €/MWh.

For natural gas, the initial price for 2022 is 40 €/MWh, suggested by Argus Media (2021). Price development scenarios follow the EIA forecasts shown in Figure 31. According to EIA, the price of natural gas will continue to fall until 2024, when it will rise again and reach the 2022 level in 2028. By 2030, EIA predicts a 4 percent, and by 2040, a 10 percent increase in natural gas prices compared to 2022 (EIA 2021). Note that EIA natural gas price forecasts refer to Henry Hub prices. However, although the price futures of natural gas produced in the USA are lower than the European TTF index, according to World Bank long-term forecasts, the relative changes in these prices are expected to be consistent (Knoema 2021).

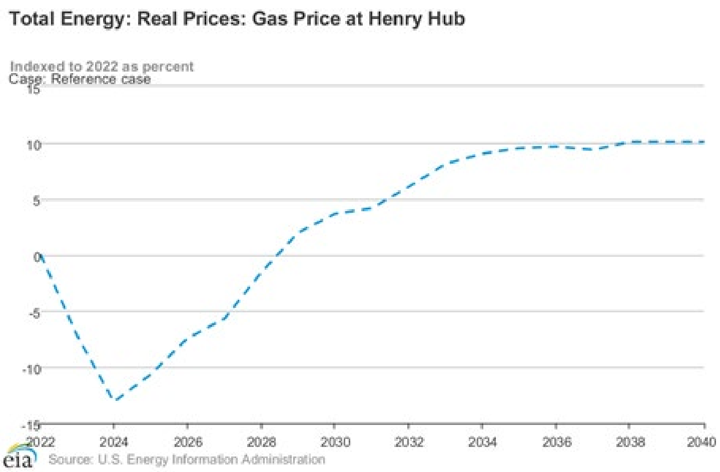

Figure 31. Predicted percentage changes of real prices of natural gas in 2022–2040 (EIA 2021).

Other threats to fossil fuel prices include energy policy decisions and taxation. Figure 32 illustrates the cost breakdown of excise duties on light fuel oil in Finland in 2011-2020. The presentation highlights the shift in focus to emission taxation.

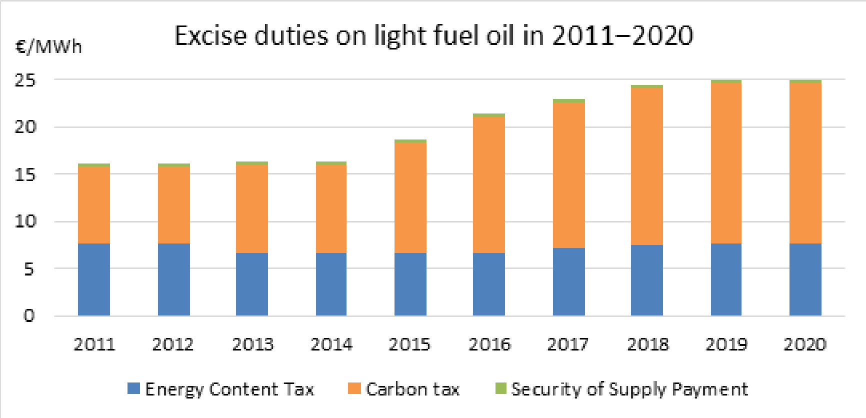

Figure 32. Cost breakdown of excise duties on light fuel oil in Finland in 2011-2020.

In 2021, excise duties continued to rise, and the current level of excise duties is 27.58 €/MWh for light fuel oil, 24.60 €/MWh for liquefied petroleum gas, and 23.35 €/MWh for natural gas (Table 16).

Table 16. Excise duties on light fuel oil, propane, and natural gas in 2021 (Tax Administration 2021a).

	Energy Content Tax	Carbon Tax	Security of Supply Payment	Total €/MWh
Light fuel oil	10.33	16.90	0.35	27.58
Propane	10.38	14.13	0.086	24.60
Natural gas	10.33	12.94	0.084	23.35

An example of future tax changes in Finland is the gradual tightening of the conditions for tax refunds to energy-intensive companies, starting from 2021 so that the excise duties paid in 2025 are no longer refundable (Tax Administration 2021b). In addition, the European Commission's Fit for 55 package, launched in July 2021, will include measures to tighten and expand emissions trading. A revision of the EU Energy Taxation Directive is also underway; the aim is to eliminate indirect subsidies and tax exemptions for polluting sectors and fossil fuels.

With rising fossil fuel prices, renewable energy sources are expected to become increasingly competitive with fossil fuels. In addition, although the key biomethane production technologies are already mature, the construction of larger and more industrialized plants may provide some economies of scale, further supporting the cost-competitiveness of biogas against fossil fuels. For example, the International Energy Agency estimates that the cost of producing biomethane in Europe could fall 25 percent from the current level by 2040 (IEA 2020). However, the production cost of individual plants can vary significantly depending on, e.g., the feedstocks used. In addition, the future taxation rate of biogas is an open question. For example, in Finland, the inclusion of biogas in the distribution obligation of transport fuels from the beginning of 2022 will require biogas taxation. In the national biogas program, an energy content tax of 10.33 €/MWh is planned for biogas, but, e.g., Finnish Energy, a branch organization in the energy sector, has proposed that only the transport use should be taxed. As already mentioned, the reform of biogas taxation is currently underway at the Ministry of Finance.

Based on the above, four price development scenarios were generated:

In Scenario 1 (Fig. 33), crude oil and natural gas prices will increase according to the EIA forecasts. The price development of propane follows the price trend of crude oil. The local availability of biomethane still relies on small-scale production, keeping the biomethane production costs at the current level of 65 €/MWh. LBG's liquefaction and distribution costs are 22 €/MWh. Excise duties on fossil fuels will remain at current levels, and biomethane will remain exempt from excise duty.

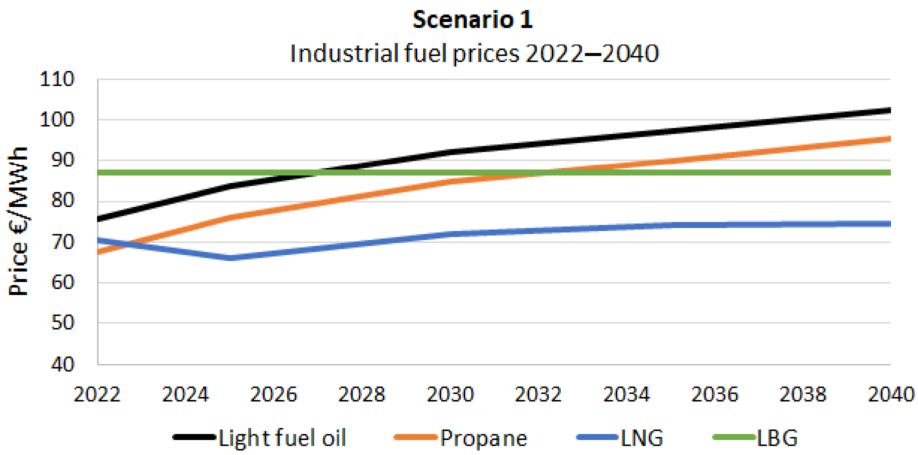

Figure 33. Industrial fuel price forecasts 2022–2040, Scenario 1.

In Scenario 1, LNG will remain the most affordable option, but LBG will be competitively priced compared to light fuel oil as early as 2027 and propane by 2032.

In Scenario 2 (Fig. 34), biomethane production takes place more centralized in larger plants. The economies of scale will reduce biomethane production cost by 25 percent from the current level by 2040, according to the IEA forecast. LBG liquefaction cost, distribution costs, fossil fuel prices, and excise duties like in Scenario 1.

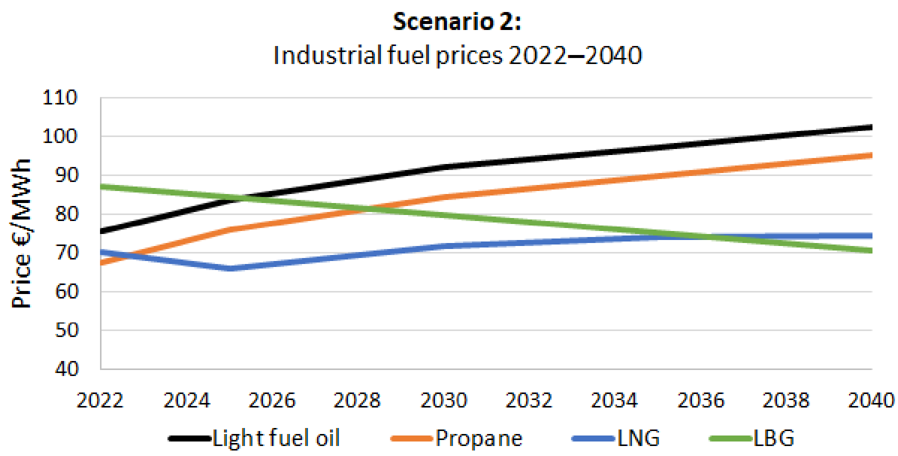

Figure 34. Industrial fuel price forecasts 2022–2040, Scenario 2.

In Scenario 2, LBG will be competitively priced with light fuel oil in 2025, propane in 2028, and LNG in 2036.

In scenarios 3 and 4, the impact of possible excise duty changes on fuel prices are also included.

In Scenario 3 (Fig. 35), fossil fuel prices are the same as in Scenario 1 and 2. Biomethane production costs like in Scenario 2, but biomethane has become subject to excise duty. The energy content tax on biomethane is 10.33 €/MWh. There is no carbon tax or security of supply payment on biomethane.

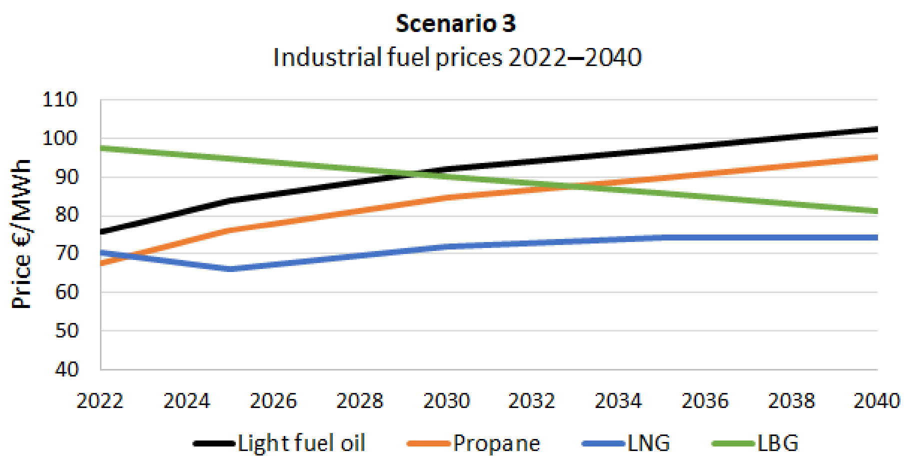

Figure 35. Industrial fuel price forecasts 2022–2040, Scenario 3.

Making biomethane subject to excise duty will slightly reduce its competitiveness compared to fossil fuels. However, the LBG price will be competitive with light fuel oil by 2029 and propane by 2032.

In Scenario 4 (Fig. 36), the effect of a carbon tax increase on industrial fuel prices is examined. In this scenario, the carbon tax on fossil fuels will rise sharply in line with taxation developments in recent years: the CO2 tax rises by 44% by 2030, and by 2040, doubles from the 2021 level. The energy content tax and the security of supply payment do not include increases compared to the 2021 level. Other assumptions as in Scenario 3.

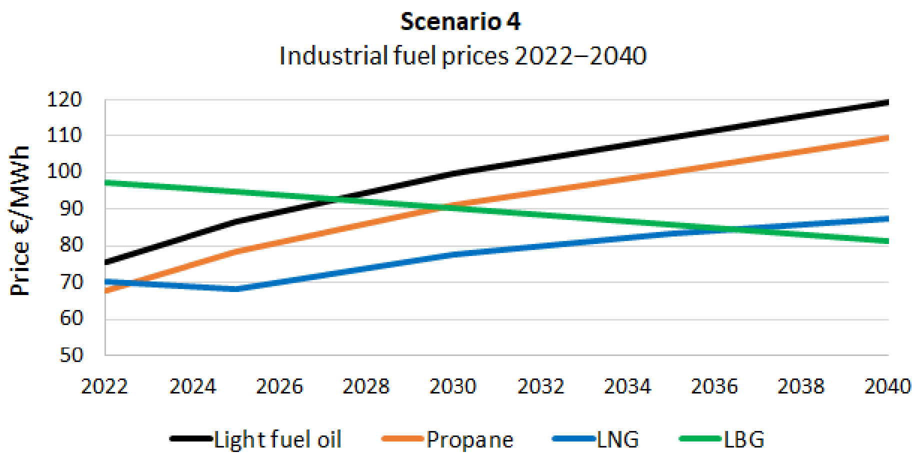

Figure 36. Industrial fuel price forecasts 2022–2040, Scenario 4.

As the tax increases focus on the emissions tax, LBG's competitiveness compared to fossil fuels will increase significantly; the LBG price will undercut the price of light fuel oil by 2028 and propane by 2030. If Scenario 4 is realized, LBG would be fully competitive with LNG in the mid-2030s.

4.4 LBG for industry: Case Wärtsilä

Wärtsilä is an internationally leading technology supplier in the marine and energy markets. The company is strongly focused on minimizing the environmental footprint of the maritime and energy industries. In 2021, Wärtsilä updated its sustainability goals, committing itself to ambitious "Set for 30" climate goals, including a commitment to becoming carbon neutral by 2030. The carbon neutrality target covers direct greenhouse gas emissions from the company's own operations, including the Research & Development and factory engine testing areas, as well as purchased energy. The toolkit includes energy savings, green electricity purchases, the use of more efficient technologies, and fuel switching. (Wärtsilä 2021.)

Wärtsilä uses natural gas in engine testing. In 2020, Wärtsilä's natural gas consumption was 8,976 tons (443 TJ) (Wärtsilä 2020a). Replacing natural gas with LBG could be a concrete action to take the company towards its carbon neutrality targets. As with other renewable fuels, CO_2 emissions from the combustion of biomethane amount to zero: The net amount of CO_2 in the atmosphere does not increase, as the amount of carbon dioxide released upon combustion equals the amount that renewable raw material has absorbed earlier. The existing natural gas systems, like distribution and storage solutions as well as natural gas engines, are fully compatible with biomethane. Therefore, shifting to biomethane would not require investments in new equipment. Biomethane and natural gas can also be mixed in any ratio, or the gases can be used alternately.

The fuel classification of Statistics Finland uses a CO_2 emission factor of 55.8 t/TJ for natural gas (StatFin 2021b). Based on this, the annual GHG emission savings from switching from natural gas to LBG in engine testing operations would be equivalent to 24,700 tons of CO_2 (CO_2-eq.). However, Wärtsilä's transition from fossil fuels to carbon-neutral or carbon-free fuels is likely to be implemeted gradually. Figure 37 illustrates the annual emission savings in CO_2-eq. as a function of biomethane share. For example, replacing 20 percent of natural gas with biomethane would lead to an annual emission reduction of 5,000 tons of CO_2-eq. With a 60 percent biomethane share, the annual emission reduction reaches 15,000 tons of CO_2-eq.

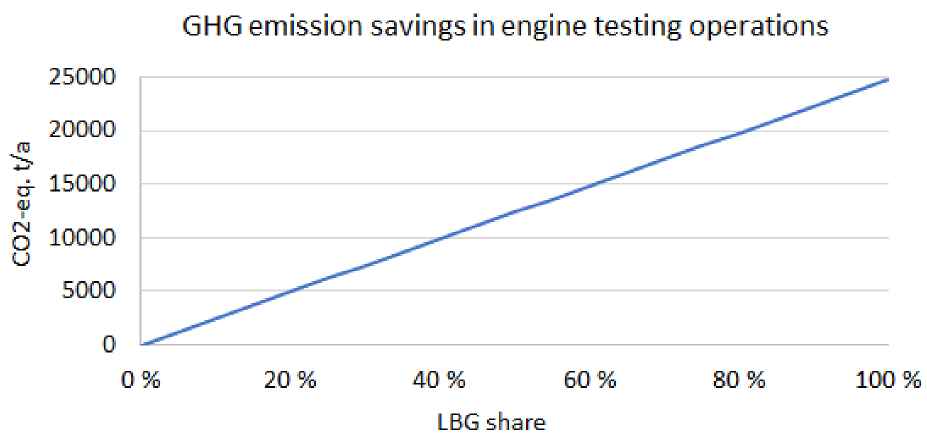

Figure 37. Annual GHG emission savings from switching from natural gas to LBG in engine testing.

4.5 Biomethane as an auxiliary fuel for a waste-to-energy plant: Case Westenergy

From the climate change point of view, wastes must be optimally utilized. In line with the goals of the circular economy, efficient recycling and reuse of materials is the key. However, not all waste can be recycled, so incinerating non-recyclable wastes is a sensible way to generate electricity and heat while disposing of non-recyclable materials. Therefore, to support the circular economy, there is a continuing need for waste incineration plants that generate energy from waste using the best available technology, with high efficiency and with minimal emissions to the atmosphere.

The Westenergy waste-to-energy plant, located in Mustasaari near Vaasa, refines combustible waste into heat, electricity, and recovered materials. The energy produced in the plant has a significant impact in reducing the need for fossil fuels in energy production in the Vaasa region: in 2019, Westenergy treated 189,638 tons of waste, generating 113 GWh of electricity and 379 GWh of district heating, covering about 50 percent of the district heating needed in the region. The plant uses moving grate incineration technology.

According to EU Directive 2000/76/EC, incineration plants shall be designed, equipped, built, and operated so that the gas resulting from the process is raised, after the last injection of combustion air, to a temperature of 850 °C. Therefore, each line of the incineration plant shall be equipped with at least one auxiliary burner. This burner must be switched on automatically when the temperature of the combustion gases after the last injection of combustion air falls below 850 °C. It shall also be used during plant start-up and shut-down operations to ensure that the temperature of 850 °C is maintained at all times during these operations. (EU Directive 2000/76/EC.) In the regular operation of the plant, no auxiliary fuel is needed if the calorific value of the waste, particularly affected by the moisture content of the waste, is sufficient. However, if the waste is too wet, auxiliary fuel must be used to incinerate the waste at the specified temperature described above.

Westenergy's waste incinerator boiler is equipped with two auxiliary burners. The total power of the auxiliary burners is 40 MW. Today, these burners are fueled with light fuel oil. The amount of Westenergy's auxiliary fuel varies somewhat from year to year depending on the net calorific value of the waste. For example, in 2019, the auxiliary fuel consumption was 159 tons, and in 2018, 178 tons, respectively. This study assumed a yearly auxiliary fuel consumption of 7,344 GJ (2.04 GWh), corresponding to 170 tons of light fuel oil. If switching exclusively to biomethane as an auxiliary fuel in Westenergy, the required annual volume would be about 146 tons of methane (lower heating value of methane 50 MJ/kg).

4.5.1 Dimensioning of gas storage

Usually, the capacity of the fuel tanks is dimensioned so that the capacity reaches a replenishment interval of about a week. However, since this is an auxiliary fuel with intermittent use, the maximum consumption of the plant's start-up and shut-down is used here as the basis for dimensioning. According to information received from Westenergy, the consumption of auxiliary fuel during the start-up is 40 m^3 (400 MWh), and during shut-down 20–30 m^3 fuel oil (200–300 MWh). Two alternative models were calculated:

Alternative 1: Dimensioning the gas storage so that the energy content of the gas to be stored corresponds to 400 MWh. This dimensioning is sufficient when downtime is anticipated, e.g., annual maintenance, and the gas storage can be filled during the downtime. This alternative requires leaving the current oil system as a backup, as in the events of unexpected outages, there may not be enough gas if the start-up follows faster than the gas storage is filled.

Alternative 2: Dimensioning the gas storage so that the energy content of the gas to be stored corresponds to the combined maximum consumption during shut-down and start-up operations (600 MWh). The advantage of this alternative is that there is no need to use oil, even in unexpected disruptions.

4.5.2 Gas storage options

Due to the low energy density of methane at atmospheric pressure, sensible alternatives can be limited to 1) high-pressure storage in gaseous form and 2) low-temperature storage in liquid form.

High-pressure storage in gaseous form

Biomethane can be compressed for transport and storage at up to 300 bar, but most typically up to 250 bar. At a pressure of 250 bar, the energy content of methane rises from 36 MJ/m^3 to 9000 MJ/m^3. High-pressure vessels have been classified into four categories based on their construction. Table 17 provides an indicative price and mass estimate for different types of pressure vessels.

Table 17. Weights and prices for type I–IV pressure vessels (Red 2014; Söderena et al. 2019).

Tank type	**Material**	**Mass (kg/L)**	**Price (€$_{2017}$/L)**
Type I	All-metal construction, generally steel	0.72–0.8	3–5
Type II	Steel or aluminum with a glass-fiber composite overwrap	0.52–0.68	5–7
Type III	Metal liner with full composite overwrap, generally aluminum, with a carbon fiber composite	0.41–0.5	9–13
Type IV	All-composite construction, a polymer liner with carbon fiber or hybrid carbon/glass fiber composite	0.24–0.33	11–17

High-pressure gas can be stored either in a fixed gas storage or in transportable gas cylinder containers. The fixed gas storage is filled from the gas supplier's transport containers on site. With fixed gas storage, heavier tank type I materials can be used, which significantly reduces the initial investment. In the case of fixed tanks, a compressor station is also required to transfer gas from one pressure tank to another. In addition, the high-pressure gas storage must also be equipped with a pressure relief system to reduce the gas pressure into values suitable for gas burners.

An alternative to fixed gas storage is storing gas in movable containers. Unlike fixed tanks, transportable containers should be designed to be as light as possible, i.e., to use solutions based on composite materials, which will double the initial investment. The maximum capacities of transportable containers are 120 MWh. However, these 45-foot containers are logistically challenging, and the most used container solutions are 20- or 40-foot containers. At a filling pressure of 250 bar, the gas volumes of these containers are 45–90 MWh.

Low-temperature storage in liquid form

The energy density of liquefied biomethane corresponds to CBG compressed to 600 bar. In addition to its high energy density, the advantage of liquefied methane is its energy-efficient transport. Liquefied methane, cooled to -161.5 °C, has a density of 423 kg/m^3 and an energy density of 21,150 MJ/m^3 (5.9 MWh/m^3).

The mass of LBG in Alternative 1 (400 MWh) is 29 tons. As the liquid filling level in LNG/LBG storage tanks is usually about 90 % (Finnish Gas Association 2021), the minimum size of the liquefied methane storage tank in Alternative 1 would be 76 m^3. In Alternative 2 (600 MWh), LBG has a mass of 43 tons, and the minimum tank volume is 113 m^3.

Before feeding the gas to the burners, the liquid LBG must be converted back to its gaseous phase in the evaporator. Generally, air vaporization is used to transfer heat from the ambient air to the liquid LBG. Typically, the gas temperature after the air evaporator is about 20 °C lower than the outside temperature. For this reason, air evaporators in Finnish conditions practically always need an after-heater, the so-called trim-heater that heats the gas to operating temperature. Alternatively, a water-glycol heat exchanger, heated with district heating or waste heat from an industrial process, can be used for evaporation. (Finnish Gas Association 2021.)

Due to its low boiling point, LBG is less suitable for long-term storage than compressed gas. Due to heat entering the cryogenic tank during storage, a part of the LBG in the tank, typically 0.1–0.5 % per day (IGU 2015), continuously evaporates, creating a gas called Boil-

Off Gas (BOG). This gas must be removed from the tank to control the tank pressure and temperature. The control of BOG is emphasized in applications where the gas use is intermittent.

4.5.3 Modifications to burners and control systems

The proposed burner technology for the Westenergy plant assumed that the existing light fuel oil system would be left as a backup system. Keeping the oil system as a backup is favored by its benefits, for example, in gas supply difficulties and unforeseen shut-down and start-up situations.

In principle, adding the possibility of burning biomethane in existing oil burners could be realizable by modifying the burners into multi-fuel burners, i.e., installing a gas lance around the existing oil lance. However, a significant part of the burner would need to be renewed with such modification. In addition, modification is often more cumbersome than building a new one and, taking into account the labor cost, the modification cost may rise close to the cost of a new multi-fuel burner. Therefore, replacing burners with new ones may be more profitable in the long term. This study assumes that the burners will be replaced with entirely new multi-fuel burners.

The existing oil valve units can likely be utilized as such. Also, there is no need to replace the combustion air blowers; the amount of air is sufficient to burn biogas. Thus, the new equipment would consist of multi-fuel burners and gas valve units.

Oilon's GKT-25K multi-fuel burner was chosen as the burner option in this study. The K-burner (Fig. 38) is suitable for demanding industrial processes, such as waste incineration. The K-burner can be equipped with several lances depending on how many fuels are used. The power range of the GKT-25K burner is 4.4–22.0 MW. (Oilon 2021.)

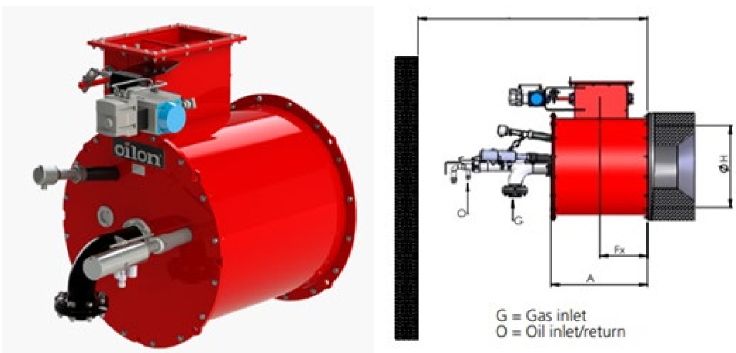

Figure 38. Oilon GKT-25K multi-fuel burner for light fuel oil and gas (Oilon 2021).

The gas pressure is reduced to suit the burner with pressure regulators in the gas valve unit. The valve unit consists of gas control and shut-off valve groups. The control valve group can be either burner-specific, or in multi-burner applications, common to all burners of the same power.

In addition, modifications to the burner automation system are required. The standard burner management systems for K-burners are WiseDrive 1000 and WiseDrive 2000. WiseDrive includes electrical control sequences, fuel/air ratio and capacity control as well as all the functions needed for safe and reliable operation (Oilon 2021).

4.5.4 Investment costs

For switching from fuel oil to biomethane, the most significant investment costs are related to gas storage. Next, the investment cost for each storage option is calculated. In addition to the gas tanks, the storage investment cost includes all the necessary auxiliary devices, such as the pressure relief unit or the vaporizer system.

Gas storage for CBG

The gas storage for compressed biomethane is assumed to be a fixed CBG storage, in which case cheaper type I steel cylinders can be used. In Alternative 1, the gas mass is 29 t, and in Alternative 2, about 43 t. With a gas density of 212 kg/m^3 (15°C, 250 bar), the tank volume in Alternative 1 is 136 m^3, and in Alternative 2, 203 m^3. The study uses a specific price of 5 €/L for the gas cylinders, and an extra 20 percent is added to the cost to cover the racks and other necessary structures for the gas cylinders. In addition, the total investment includes a compressor that is needed to transfer the gas from the transportation container to the fixed gas tanks, and pressure reduction equipment to reduce the gas pressure prior to feeding it to the burners. The cost estimate for the compressor and the pressure relief equipment is based on the price estimate received from an equipment supplier.

Table 18. Gas storage for CBG, Alternative 1 (400 MWh).

Steel cylinders, total volume 136 m^3 + racks	816 000 €
Pressure reduction unit	360 000 €
Compressor	210 000 €
Foundations and earthworks	50 000 €
Installations, cabling, etc.	20 000 €
Total	**1 456 000 €**

Table 19. Gas storage for CBG, Alternative 2 (600 MWh).

Steel cylinders, total volume 203 m³ + racks	1 218 000 €
Pressure reduction unit	360 000 €
Compressor	210 000 €
Foundations and earthworks	60 000 €
Installations, cabling, etc.	20 000 €
Total	**1 868 000 €**

Gas storage for LBG

Haimila (2015) presented a cost estimate for a 78 m^3 LNG tank and the vaporizer of 150,000–200,000 €, of which the vaporizer accounts for 30,000 € (Heinonen 2016). Based on these, the cost of the tank is 1,540–2,180 €/m^3. In this work, the unit price for the tanks was set at 2,000 €/m^3. In addition, a concrete foundation is needed to support the tank load. The construction cost of the larger tank is increased by the construction of a leak collection required for tanks of 100 m^3 and larger. Installation costs, including labor cost and crane rental cost are from (Heinonen 2016). The foundation costs, transportation costs, as well as instrumentation and electrification costs are based on prices estimated by the author.

Table 20. Gas storage for LBG, Alternative 1 (400 MWh).

LBG storage tank 76 m^3	152 000 €
Vaporizer	30 000 €
Foundation and earthworks	40 000 €
Transportation and installation	20 000 €
Instrumentation and electrification	30 000 €
Total	**272 000 €**

Table 21. Gas storage for LBG, Alternative 2 (600 MWh).

LBG storage tank 76 m^3	226 000 €
Vaporizer	30 000 €
Foundation and earthworks	60 000 €
Transportation and installation	30 000 €
Instrumentation and electrification	30 000 €
Total	**376 000 €**

Piping

The total cost of piping installation from gas storage to the gas valve unit was set at 10,000 € (50 meters, DN200 pipe installed underground, price estimate 200 €/m).

Burners and burner control

The total cost estimate for burners and burner control is 180,000 €, including:

- two GKT-25 K multi-fuel (oil and gas) burners with accessories
- burner control system WD 1000
- gas pipeline and fittings from gas valve unit to boilers

4.5.5 Summary of investment costs for different options

The total investment cost estimates for each option are summarized in Table 22.

Table 22. Total investment cost.

	400 MWh		600 MWh	
	CBG	LBG	CBG	LBG
Gas storage	1 456 000	272 000	1 868 000	376 000
Piping	10 000	10 000	10 000	10 000
Burners and burner management	180 000	180 000	180 000	180 000
Total investment (€)	**1 646 000**	**462 000**	**2 058 000**	**566 000**

The above cost estimates do not consider the costs of licensing and permitting and regulatory inspections, nor the project's overhead costs, such as project planning and management.

When comparing total investment costs, the LBG option appears more advantageous. However, in the case of liquefied gas, the management of boil-off gas associated with intermittent gas use poses challenges. If the boil-off gas is not fed into the process regularly, it must be recovered and further processed for later use, like compressed and sent to a condenser for re-liquefaction or fed to a separate gas storage. Please note, this study did not comment on the BOG management method and, therefore, did not consider the costs of the BOG management system, which may significantly impact the final costs. Extended storage times may also degrade LBG quality (IGU 2015). In addition, LBG supply may be an issue, as the availability of liquefied biomethane is currently quite limited.

4.5.6 GHG emission savings from fuel switching

Reducing greenhouse gas emissions is one of the main drivers for bioenergy. As with other renewable fuels, the combustion of biogas, made from organic waste streams, does not add to the CO_2 load in the atmosphere. Biogas combustion does generate CO_2, but there is no net increase in atmospheric carbon dioxide because the amount of CO_2 released during biogas combustion is the same that was bound to the biodegradable feedstock.

The CO_2 emission factor used in GHG inventory for light fuel oil (with 0 % bio share) is 73 t CO_2/TJ fuel (StatFin 2021b). Assuming an average annual auxiliary fuel consumption of 170 t light fuel oil, corresponding to energy content of 7,344 GJ, the CO_2 savings achieved by fuel switching from light fuel oil to biomethane would be 535 tons of CO_2 per year.

4.6 Utilization of biogas in the greenhouse industry

In order to increase the amount of biogas produced in the Ostrobothnia region, different kinds of substrates need to be utilized more efficiently in existing biogas production facilities and facilities to be built in the future.

Ostrobothnia has traditionally been a region in Finland with many greenhouse companies which are particularly aggregated in the southern parts of the region. It was therefore of interest to investigate in the present project how much biomass waste accumulates from greenhouse cultivations, whether the biomethane potential of different plant wastes in anaerobic digestion is satisfying, how much energy greenhouse companies consume and whether biogas could be used as a fuel for heat and/or electricity production in the industry. Moreover, it was investigated whether carbon dioxide from biogas upgrading into biomethane could be used as carbon fertilizer in greenhouse cultivation. The study was done as a desk top study.

4.6.1 Amount of plant waste generated in greenhouse production

The generation of biomass waste from greenhouses naturally depends on cultivation areas and amount of products produced. The Natural Resources Institute Finland is gathering information from Finnish horticulture enterprises on greenhouse area, cultivation area, cultivated plant and yield on an annual basis. These data are accessible online and have been used for the present study.

In year 2021, there were 838 greenhouse enterprises (enterprises that exceeded an economic threshold of 2 000 EUR) in Finland cultivating on a total greenhouse area of 375 hectares. Of these enterprises, 155 (18.5%) were registered in Ostrobothnia with a total greenhouse area of 123 hectares (32.8% of total greenhouse area in Finland). During the past ten years, both number of enterprises and total greenhouse area in Finland has decreased. (Natural Resources Institute Finland 2022a)

In Finland in 2021, a total of 98 million kilograms of greenhouse vegetables were produced, of which there were 53 million kilograms greenhouse cucumber and 38 million kilograms greenhouse tomato. Special tomatoes amounted to 7.4 million kilograms of tomato yield. Ornamental plants were cultivated in 2021 in greenhouses on an area of 114 hectars. (Natural Resources Institute Finland 2022b)

For the present study, focus was put on tomato and cucumber production in Ostrobothnia, because these are the vegetables with the largest cultivation area and a continuous weekly accumulation of biowaste in the form of leaves and vegetative side shoots. Other potted vegetables such as lettuce and herbs are produced on a much smaller area. Also, about 70% of tomatoes and almost 80% of cucumbers that are produced in Finland are being cultivated in the Ostrobothnia region (Figure 39).

Both tomato and cucumber can be cultivated in either year-round or seasonal cultivations. In a seasonal tomato cultivation, the plants are usually planted in February to March and the cultivation is terminated in October. A tomato plant starts giving yield approximately eight weeks after plantation. In a year-round cultivation, the plants are planted in August or September and they will be removed from the greenhouse in July or August the following year. Cucumber can also be cultivated either seasonally or year-round. Either way, the individual plants will be maintained and yielded for 12 to 15 weeks and then exchanged. Seasonal cultivation can last for seven months or less. When cultivated in year-round manner, the plants will be changed three to four times. (Murmann 1996; Niemi 2019; Kymäläinen & Suojala-Ahlfors 2020).

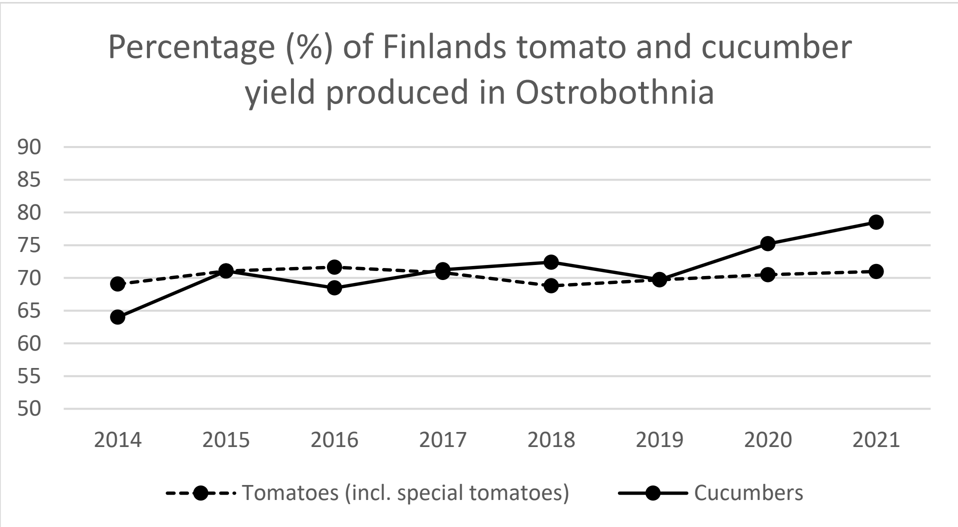

Figure 39. Percentage of Finland’s tomato and cucumber yield produced in Ostrobothnia. (Result computed from data from Natural Resources Institute Finland 2022b.)

The production of tomato (including special tomatoes) is shown for Finland and Ostrobothnia for the years 2014 through 2021 in Figures 40 and 41. In 2021, a total of 27 million kilograms of tomatoes (including special tomatoes) were produced in Ostrobothnia (Figure 40). Production in these years has varied between 27 and 29 million kilograms, and tomato has been cultivated on an area of between 60 to 70 hectares (Figure 41).

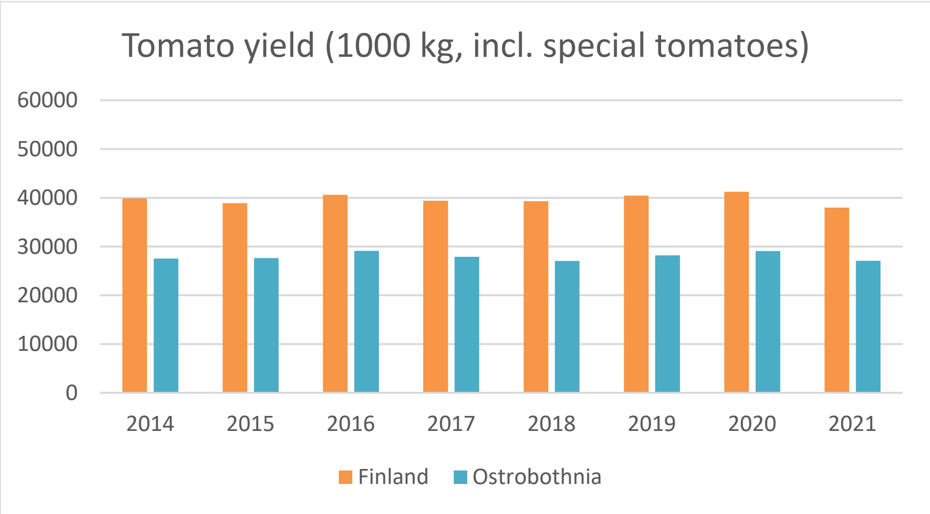

Figure 40. Tomato yield (in 1000 kg) in Finland and Ostrobothnia from 2014 through 2021. (Data from Natural Resources Institute Finland 2022b.)

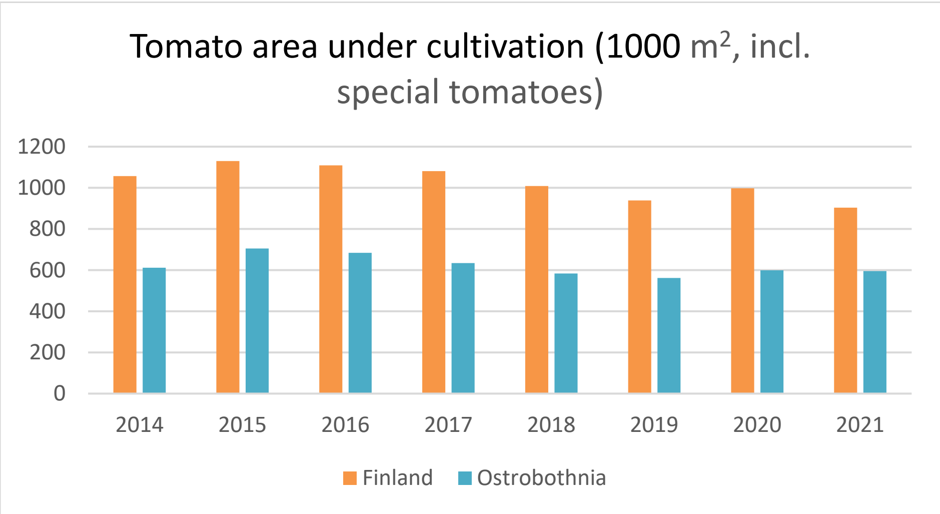

Figure 41. Tomato area under cultivation (in 1000 m^2) in Finland and Ostrobothnia from 2014 through 2021. (Data from Natural Resources Institute Finland 2022b.)

The production of greenhouse cucumber in Ostrobothnia has increased from 24.5 million kilograms in 2014 to 41.6 million kilograms in 2021 (Figure 42). The area on which cultivation has taken place in these years varied between 31 and 56 ha (Figure 43).

A literature example for a year-round early tomato crop indicated that leave and stem weight accounted for 18% of the achieved yield (De Koning 1993 referred to in Heuvelink 2005). Another example stated for France that the amount of greenhouse residues is estimated at approximately 170 t/ha of the area of greenhouses (Boulard et al. 2011 referred to in Oleszek et al. 2016). Dorais & Dubé (2011) referred to a waste production of tomato leaf biomass of 4.5 t/(ha*week), or 450 grams per m² and week.

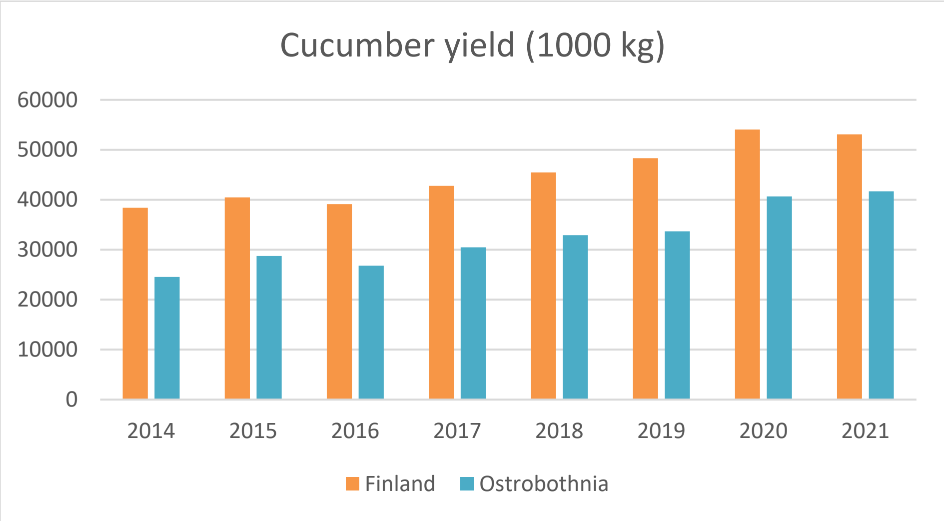

Figure 42. Cucumber yield (in 1000 kg) in Finland and Ostrobothnia from 2014 through 2021. (Data from Natural Resources Institute Finland 2022b.)

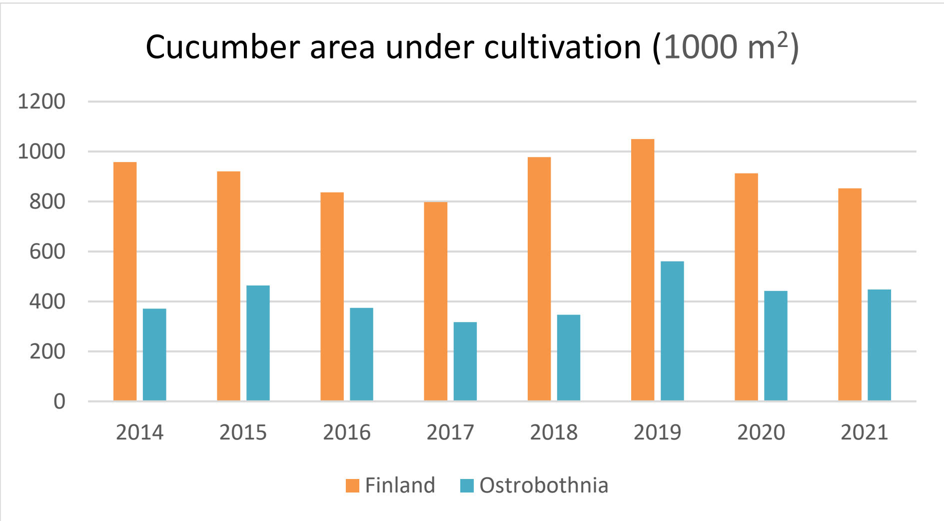

Figure 43. Cucumber area under cultivation (in 1000 m²) in Finland and Ostrobothnia from 2014 through 2021. (Data from Natural Resources Institute Finland 2022b.)

The amount of biowaste from tomato and cucumber greenhouse cultivation has been assessed and estimated in previous Finnish studies which are reviewed here (compare Table 23). In his Master Thesis, Söderlund (2011) evaluated the amount of waste from tomato and cucumber cultivation based on information received from greenhouse growers and information on the area of cultivation in year 2008. According to the study, 10 801 tons of tomato waste were likely to have been produced on a total area of 66.8 ha, and 5 205 tons of cucumber waste on a total area of 26.4 ha. Together this amounted to 16 000 tons of biomass waste.

In a study by Haapanen & Kannonlahti (2019), the amount of 16 000 tons of tomato and cucumber waste was estimated to accumulate merely in the south-ostrobothnian region of Kristiinankaupunki, Kaskinen, Närpiö and Korsnäs. The cultivation area was 50 ha for tomato and 22.5 ha for cucumber.

Niemi (2019) presented an estimate made by Mikael Dahlqvist at the cooperative Närpes Grönsaker for waste leaf biomass from tomato and cucumber, based on leaf weight and number of leaves that are removed from the plants in relation to 1 kilogram of yielded fruits. For one kilogram of tomato fruits, four leaves at 42 grams each are being removed, and for one kilogram of cucumber fruits, three leaves at 35 grams are being removed. Stems and side shoots were not included in this measure. This approach gives an estimate on biomass waste production independent of the cultivation area. The estimate does not include stem or shoot material.

In the BioArvo project (Kymäläinen & Suojala-Ahlfors 2020), weight of leaves and stems and fruits were assessed in a tomato year-round cultivation. Production of waste biomass was also estimated in interviews. According to the study, vegetative biomass waste amounts by weight to about 25-35% of yielded tomatoes, and 40-60% of yielded cucumbers.

In the present study, the weight of a tomato plant in a year-round cultivation was estimated to be 7 kg, and that of a plant in a long cultivation (lasting at least 7 months) was estimated to be 5 kg. The area of lighted cultivation (i.e. cultivation lasting from 10 to 12 months and employing artificial lighting) was taken from the statistics. It was assumed that a cucumber plant would produce approximately 3.7 kg of leaves, side shoots and stems, or about 15% of the yield weight.

Table 23. Assessment of biowaste amounts from greenhouse tomato and cucumber cultivations by different authors.

Reference	**Calculation**	**Tomato**	**Cucumber**
Master Thesis, M. Söderlund (2011)	Biomass removal per plant and week	0.19 kg/week	0.33 kg/week for short season; 0.25 kg/week for long season and year-round
Master Thesis, S. Niemi (2019)	Biomass (leaves only) as percentage of yield	4 leaves à 42 g per 1 kg yield	3 leaves à 35 g per 1 kg yield
Kymäläinen & Suojala-Ahlfors (2020)	Biomass (leaves and stems) as percentage of yield	25% … 35% of kg yield	40% … 60% of kg yield
Present study	Estimated plant specific weight; percentage of yield	7 kg/plant in artificially lighted cultivation (10-12 months); 5 kg/plant in long cultivation (at least 7 months)	3.7 kg/plant; or 15% of yield

In a subsequent step, estimates were calculated for the minimum and maximum biomass waste accumulation based on the calculations used in the previous studies (Table 23), and the area and yield data of tomato and cucumber cultivation in Ostrobothnia in 2021 (Figures 40 through 43). Thus, the amount of biomass waste from tomato cultivations is estimated to have been between roughly 7 000 and 10 000 tons in 2021 (Figure 44). Waste tomato leaf biomass would have amounted to 4 500 tons (fresh weight). The estimate for cucumber is more wide, ranging from 5 000 tons up to 25 000 tons (Figure 45).

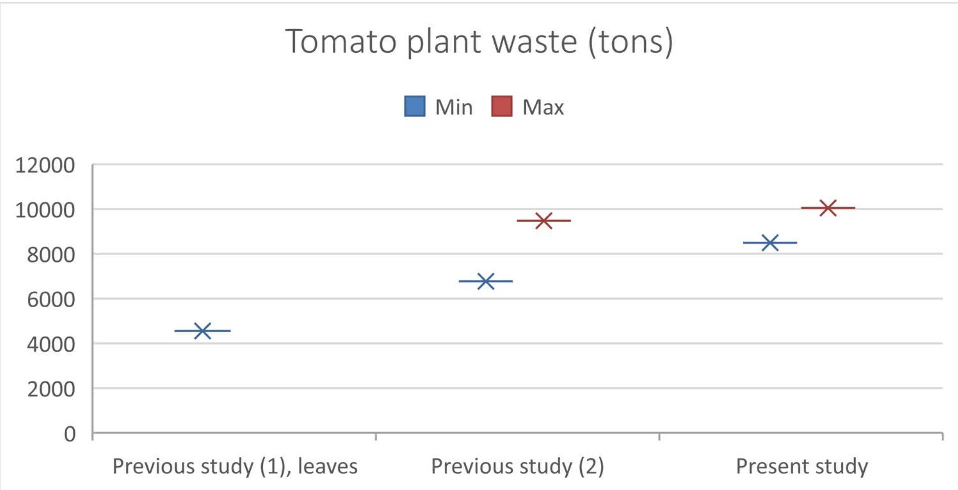

Figure 44. Estimated minimum and maximum tomato plant waste accumulation in Ostrobothnia in 2021. Estimations for 2021 data employed ways of calculation from two previous studies (1): Niemi 2019; (2): Kymäläinen & Suojala-Ahlfors 2020.

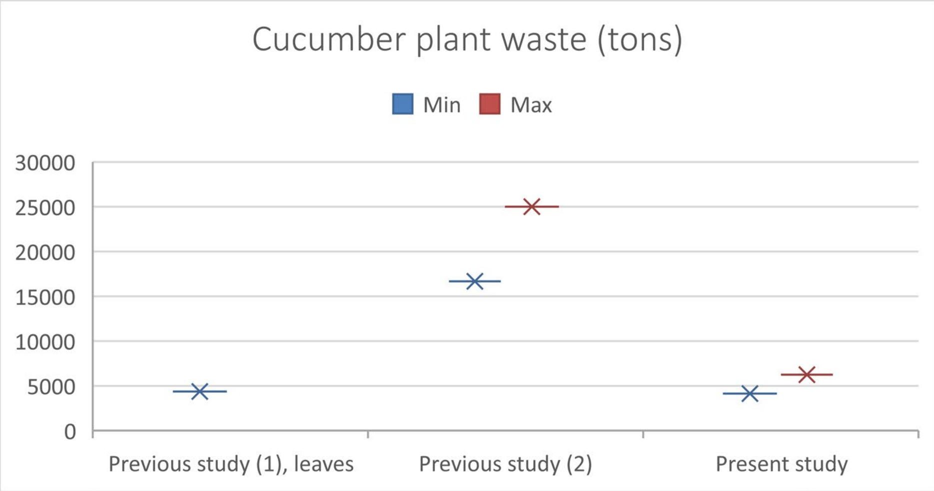

Figure 45. Estimated minimum and maximum cucumber plant waste accumulation in Ostrobothnia in 2021. Estimations for 2021 data employed ways of calculation from two previous studies (1): Niemi 2019; (2): Kymäläinen & Suojala-Ahlfors 2020.

4.6.2 Biomethane potential of plant waste

For the purpose of increasing biogas production, substrates are needed that are suitable for anaerobic digestion. The biomethane potential of tomato and cucumber vegetative waste (leaves, stems) has been measured in several studies. Moisture of tomato and cucumber biomass has been considered suitable for processes that operate with material of 12-15% total solids (TS) (Kymäläinen & Suojala-Ahlfors 2020). Kymäläinen & Suojala-Ahlfors (2020) presented results from laboratory experiments in which they tested the biomethane potential (BMP) of tomato and cucumber leaves and stems (Table 24). Digestion of leaves of both plants resulted in higher BMP than digestion of stems (240 versus 290 mL CH_4/gVS for tomato; 290 versus 310 mL CH_4/gVS for cucumber; VS: volatile solids).

In a project at Novia University of Applied Sciences, the biomethane potential was tested for several different substrate mixtures in an Automatic Methane Potential Test System (AMPTS), an analytical laboratory device (Table 24) (Öling-Wärnå et al. 2019). For instance, tomato leaves were digested together with chicken manure and fish waste (from fish gutting), and in another test series tomato leaves were mixed with biowaste from households and with pig slurry. The proportion of different materials varied from between 10% to 80%. The results showed that the biomethane potential varied for the different mixtures between 200 Nml/gVS ja 762 Nml/gVS. A high proportion of tomato leaves (80%) in the mixture resulted in a lower biomethane production in both test series. When the materials were mixed at even input of 33%, the results showed biomethane potential from 344 to 375 Nml/gVS. The highest biomethane output was reached when fish waste formed 80% of the mixture.

Cucumber leaves were digested together with fox manure (from fur farming) and biowaste from households. As for tomato, the proportion of the substrates varied between 10% and 80%. The test series were run twice. The results showed that the biomethane potential varied between 193 Nml/gVS and 515 Nml/gVS. The highest value (515 Nml/gVS) was reached in a mixture with 80% biowaste from households. The lowest values resulted from mixtures with 45% cucumber leaves, and 80% fox manure. Mixtures with an equal amount of each material (33%) produced 303 ... 328 Nml/gVS of biomethane.

It was observed by Öling-Wärnå et al. (2019) in the laboratory experiments that the onset of biomethane production in the mixtures “household biowaste – fox manure – cucumber” was delayed by up to 10 days in the beginning of the digestion experiments. The onset of digestion of substrates containing tomato leaves was quicker, but methane production was considered low. Öling-Wärnå et al. pointed out that the start culture was not specifically adjusted to digesting biowaste from cucumber or tomato plants. In addition, the chemical composition of the start culture was noted to affect the value for the co-digestion which made it difficult to interpret the contribution of the substrates. The start cultures were from two different biogas plants, one operating a mesophile process at 37 °C, and the other one operating a thermophile process at 55 °C. Start cultures from the thermophile process were from either a reactor digesting wastewater treatment sludge or municipal biowaste. All in all, in the study by the Novia University of Applied Sciences, it can be observed that the higher the proportion of cucumber or tomato waste in the mixture, the worse was the biomethane yield.

Oleszek et al. (2016) reported a biomethane production potential of 300 mL CH_4/gVS and 280 mL CH_4/gVS for stems, leaves and stalks from tomato and cucumber plants, respectively.

The biomethane potential of tomato and cucumber waste biomasses is lower than that of other substrates such as for instance biowaste from households (approximately 450 mL CH_4/gVS), but it is comparable to the values as given in literature for grass from natural fields and straw (280 mL CH_4/gVS for both materials) (TEM 2020). However, the amount of total solids and volatile solids is much higher in these substrates than in tomato or cucumber biomass waste.

Tomato contains glycoalkaloid compounds tomatine and tomatidine, of which tomatine was noticed to negatively affect on biogas yield in mesophilic batch experiments (Szilágyi et al. 2021). The authors presented that tomato waste can have inhibiting effects on the microbial community that accomplish the digestion of the organic substrate. It had also been observed that tomato waste can change the composition of the micro-organism community in a continuous digestion process. The authors further investigated effects of effluent after digestion of tomato waste on lettuce seed germinability, and found that there was no inhibition of a 3v/v-% solution on germination. (Szilágyi et al. 2021) In summary, vegetative waste of tomato and cucumber plants can be useful to digeste in combination with other substrates.

In the next step, for the calculation of how much energy could be produced by digesting tomato and cucumber biomass waste, the biomethane potential was assumed to be 290 mL CH_4/gVS, the amount of total solids was assumed to be 15% for tomato, and 10% for cucumber, and the amount of volatile solids per total solids was assumed to be 75% for both plant wastes (Table 25). Thus in total, biomethane with an energy content of 4.3 GWh could be expected from the digestion of tomato and cucumber biomass wastes in Ostrobothnia.

Table 24. Biomethane potential values from laboratory scale experiments reviewed from the literature.

Substrate	BMP (mL CH_4/gVS)	Reference
Tomato leaves Tomato stems Cucumber leaves Cucumber stems	290 225-250 310 290	Kymäläinen and Suojala-Ahlfors 2020 (values approximate, because taken from a graph)
10% fox manure – 10% municipal biowaste – 80% cucumber leaves 33% fox manure – 33% municipal biowaste – 33% cucumber leaves 10% municipal biowaste – 10% pig manure – 80% tomato leaves 33% municipal biowaste – 33% pig manure – 33% tomato leaves 33% tomato leaves – 33% chicken manure – 33% fish waste (salmon) 80% tomato leaves – 10% chicken manure – 10% fish waste (salmon)	252 / 325 303 / 240 / 309 248 356 / 355 / 355 347 / 344 / 375 219	Öling-Wärnå et al. 2019, Appendix
Tomato fresh residue (stems, leaves and stalks) Cucumber fresh residue (stems, leaves and stalks)	301 280	Oleszek et al. 2016
55-75% tomato – 45-25% cucumber	292	Gil et al. 2015
Fresh cucumber waste Fresh tomato waste	260 320	Jagadabhi et al. 2011

Table 25. Calculation of potential energy production based on biomethane production from tomato and cucumber biomass waste. Biomass waste accumulation as estimated in the present study. (TS: total solids; VS: volatile solids).

	Biomass waste (tons)	TS (%)	VS of TS (%)	CH_4 mL/gVS	MWh
Tomato 2021	10 000	15	75	290	3 262
Cucumber 2021	5 000	10	75	290	1 088
Sum					4 350

Haapanen & Kannonlahti (2019) calculated that a total of 5.7 GWh biogas could be produced from 14.4 tons of tomato waste plus 1.5 tons cucumber plant waste produced in the southern parts of Ostrobothnia before 2018. The authors used a gas production potential of 330 m^3 CH_4/t. The dry matter content was assumed to be 15% for tomato and 10% for cucumber. A value of 75% volatile solids (VS) per dried biomass was used in the calculations.

Kymäläinen & Suojala-Ahlfors (2020) evaluated that 6 MWh energy could be produced by anaerobically digesting tomato and cucumber residues from the whole of Finland.

Waste from greenhouses has to be handled in a way that is not affecting negatively on the environment (Länsirannikon ympäristöyksikkö 2020). This means that greenhouse enterprises can either compost their biowaste themselves or send the biowaste for composting by another company or to a biogas plant for anaerobic digestion. Substrate slabs that are made of peat or other organic material like for instance coconut fibres are organic and can in small amounts be mixed into field soils or into compost (Länsirannikon ympäristöyksikkö 2020). At present, there do not seem to exist public figures on how much biomass waste from greenhouse enterprises is composted and how much is processed in biogas plants in Finland or Ostrobothnia. Evidently, the estimated energy of 4.3 GWh might already in part be produced by biogas plant enterprises, and not be an additional fully accessible asset in the region.

Some research has even investigated other options of treating greenhouse biomass waste. Oleszek et al. (2016) evaluated in their work the possibility to ensilage tomato and cucumber waste as a means of storage prior to anaerobic digestion. The conclusion was that digesting the fresh biomass waste resulted in a higher production of biogas and biomethane. The authors also investigated the production of energy and carbon dioxide from anaerobic digestion and combustion. They concluded that combusting dry greenhouse wastes resulted in higher heat energy output than anaerobic digestion, but the process of drying itself is energy-intense. Moreover, there is also the risk of fouling and slagging of the combustion chamber because tomato and cucumber materials contain high amounts of alkali and alkaline earth materials and thus have a high alkali index.

4.6.3 Thermal and electrical energy needs of greenhouse enterprises

Energy consumption in the Finnish greenhouse industry (Figure 46) is regularly surveyed by the Natural Resources Institute Finland. The primary producers are asked to fill in the survey every three to four years for heated greenhouses with an area of at least 1 000 m^2. The results are available from the horticultural statistics at the Natural Resources Institute Finland (2022 c).

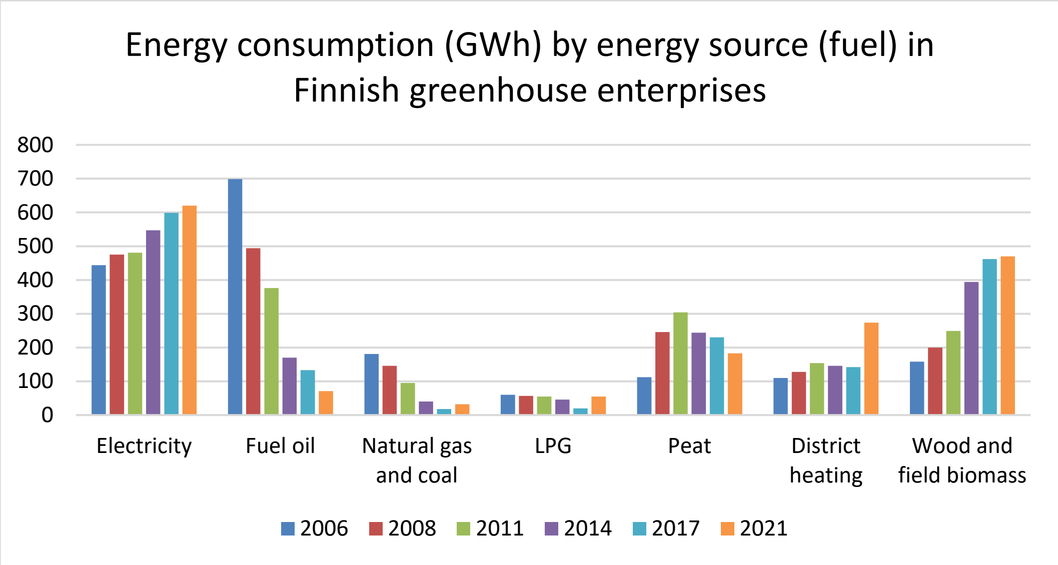

Figure 46. Energy consumption in GWh by energy source in Finnish greenhouse enterprises. Category oil includes heavy and light oil; in category natural gas and coal also shown anthracite; category peat includes pellets, sod and milled peat; category wood and field biomass includes wood chips, pellets, briquettes. (Data from Natural Resources Institute Finland 2022c.)

The data shown in Figure 46 depict the energy consumption of all Finnish greenhouse enterprises, not only the enterprises in Ostrobothnia. The heat and electricity demands in Finnish greenhouse enterprises amounted to 1706 GWh in 2021. The consumption of electricity has continuously risen since the first survey in 2006. While in 2006 the primary producers declared a total of 444 GWh of electricity consumption, the sum was 620 GWh in 2021, almost 40% more than in 2006. In comparison to the previous survey year 2017, electricity consumption had risen by 3%. The fuel oil (heavy and light) was the main source for heat in 2006 with 699 GWh, and its consumption has continuously decreased since then. Only 36 companies used heavy fuel oil and 355 light fuel oil in 2021 equivalent to an energy content of 71 GWh.

In 2006, a few companies reported to have used hard coal and anthracite and 30 companies reported to have used natural gas. The categories of hard coal, anthracite and natural gas were surveyed as one category starting from 2014. In 2021, only 13 companies declared the use of hard coal/anthracite/natural gas. The use of LPG has been at a level of around 40 to 60 GWh. The use of peat (milled, sod, pellets) peaked with 304 GWh in 2011 and has decreased since. Nevertheless, energy produced from peat constitutes still about 10% of the energy consumption by greenhouse enterprises. Finland's government's goal is to halve the usage of peat in energy production by 2030 in pursuit of meeting emissions reductions (Finnish Government 2019).

The use of wood biomass (including pellets, chips, briquettes) and field biomass has continuously increased from 158 GWh in 2006 to 611 GWh in 2021, 3.8 times the value in 2006. The value for 2021 includes direct use of wood and field biomass and a proportion of the district heating that is produced with materials from forest and field. District heating (or purchased heat energy) had been on an even level for many years, but almost doubled from 142 GWh in 2017 to 274 GWh in 2021. Energy from renewable energy covered 56% of the heating energy in 2021 (Natural Resources Institute Finland 2022d).

Borg (2011a) investigated energy consumption in greenhouse cultivation in Ostrobothnia by analysing statistical data and data given by greenhouse enterprises. The data was analysed with different approaches. Results of a multi-variate analysis showed that the average energy consumption of a tomato long season cultivation (cultivation lasting at least 7 months) with artificial lighting lays at 1.3 MWh/m^2, and at 1.16 MWh/m^2 for a long artificially lighted cultivation of cucumber. For tomato in a long artificially lighted cultivation, the area specific consumption of electricity was 0.67 MWh/m^2, and fuel consumption for heat 0.63 MWh/m^2. For cucumber in a long artificially lighted cultivation, electricity consumption laid at 0.88 MWh/m^2 electricity and 0.28 MWh/m^2 of fuel consumption for heat production. Energy consumption (electricity and heat) was lower for cultivations without artificial lighting and naturally for short season cultivations.

The annual greenhouse energy demand in Poland and other countries of Northern Europe (The Netherlands, Germany) has been stated to reach 36 TJ ha-1 (Oleszek et al. 2016, and references herein). This is equivalent to 10 GWh or 10 000 MWh per hectare, or 1 MWh per m^2.

Tataraki et al. (2020) calculated the average annual energy demand for heating and cooling for the EU-27 countries (Figure 47) based on climatic data (ambient temperature and solar radiation) from the years 2008 to 2018. According to the study, the average heating requirement for a greenhouse in Finland is approximately 850 kWh/m^2/year. This is the highest energy requirement in any of the EU countries. The heating requirement of Swedish greenhouses laid under 800 kWh/m^2/year. Both countries showed the same demand for heating in number of days per year, approximately 90 days. The value of 850 kWh is somewhat higher than the results from the data analysed by Borg (2011a). Artificial lighting with the help of high-pressure sodium lamps reduces the demand for heat production from other fuels. High-pressure sodium lamps are so far predominating in year-round greenhouse cultivation in Ostrobothnia, although there is an increased number of greenhouse enterprises that have installed for instance LED-lamps as an additional lighting source.

In summary, the use of renewable energy sources in the form of wood and field biomass has clearly replaced the use of fossil energy sources between 2006 and 2021 in Finnish greenhouse horticulture. In contrary to The Netherlands, where the majority of energy supply to greenhouse horticulture was still mainly provided by natural gas, namely 78% of the energy in 2019 (Van der Velden & Smit 2020), the use of natural gas has never been widely spread in Finnish greenhouse culture.

The energy content of biogas produced in 2021 in Finland was approximately 1 TWh (Spoof-Tuomi 2021). The energy consumption by greenhouse enterprises was 1.7 TWh. Thus, it is evident that the energy demand by Finnish greenhouse enterprises cannot presently be covered by the use of biogas. According to the forecast given by the Finnish Biocycle and Biogas Association, in Finland, in year 2025, there might be the capacity of 538 GWh biomethane and 905 GWh biogas, in total 1 442 GWh (Virolainen-Hynnä 2021). This estimation is based on the existing biogas plants in 2020 and the public investment plans in biogas for the years 2021 to 2025. Hence, the energy provided by biogas and biomethane would potentially be much closer by value to the energy demand as it is today in greenhouse horticulture, not regarding the spatial distance between biogas producers and consumers.

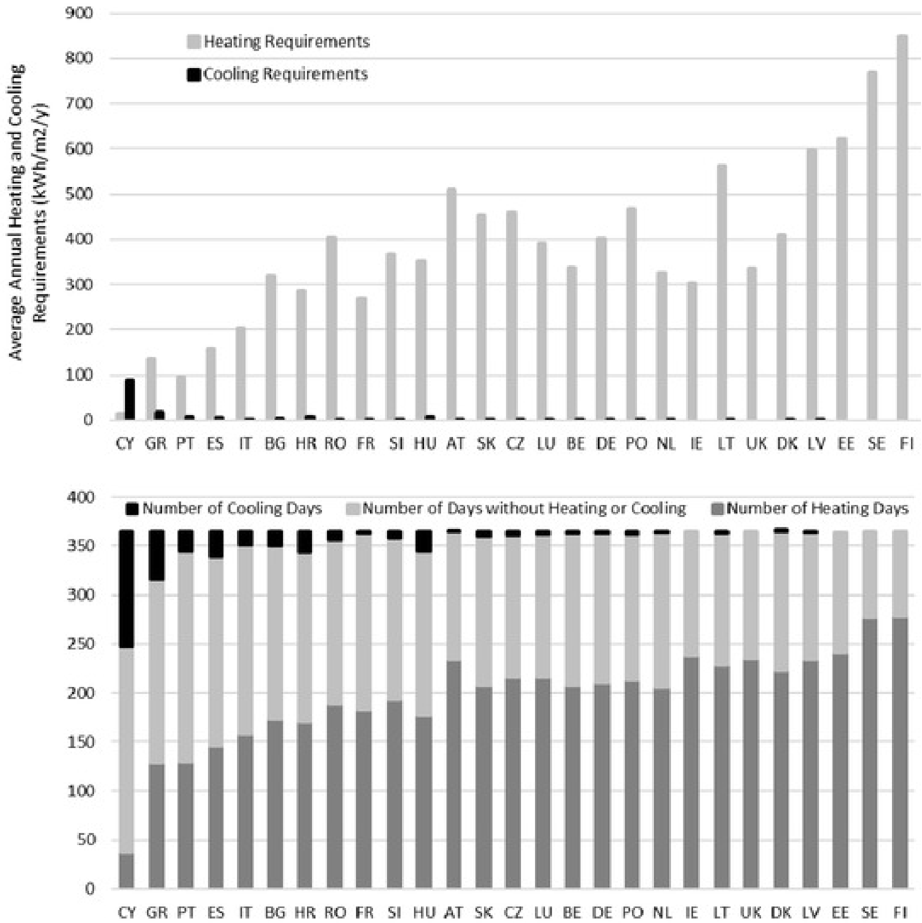

Figure 47. Annual heating and cooling requirements (upper graph), and number of days with heating or cooling or no energy requirements (lower graph). Reproduced from Tataraki et al. (2020) under a Creative Commons Attribution license (CCBY 4.0).

4.6.4 Technical solutions for using biogas

Biogas can be utilized in biogas fired boilers to produce heat, in microturbines, or in gas engine cogeneration systems to produce heat and electricity. In the cogeneration or combined heat and power (CHP) plant, the central system consists of a gas engine, a generator and heat exchangers that collect waste heat from the engine's cooling water, the oil circuit and exhaust gas. With a gas engine, the total efficiency can be approximately 90% and the efficiency in electricity production 38...46% depending on the engine size. Fuels for gas engines comprise natural gas, landfill gas and biogas from digestors, and gas from biomass and waste gasification. The produced electricity and heat can be used on site, or electricity is fed to the grid and heat is provided to other consumers.

Heat from the CHP can be used to warm greenhouses and the produced electricity can be used in the greenhouse operations and artificial lighting if installed. An additional heat accumulator gives more flexibility to the system. Moreover, carbon dioxide produced during combustion can be used for carbon fertilization in greenhouses after suitable purification and cooling of the exhaust gases. Some examples of manufacturers of cogeneration systems using gas engines are given in Table 26. There are many more manufacturers in the market providing gas engines and CHP units, often to meet a higher power demand. For instance, Wärtsilä offers combined heat and power plant solutions (also including cooling) that can run on a range of liquid, gaseous and biofuels (Wärtsilä 2020b).

Table 26. Examples of outputs and efficiencies of some gas engines and power generators of selected manufacturers. Ranges of values for engine types are shown for biogas applications. For precise information on specific engine and output, refer to the manufacturers' product brochures (INNIO Jenbacher 2021; Caterpillar Energy Solutions 2022; MAN 2022; Rolls-Royce 2022).

	Electrical power (range) with biogas	**Total efficiency with biogas**	**Utilizing exhaust gas for CO_2 fertilization**	**H_2 readiness of products**
Jenbacher	249 kW_{el} ... 3360 kW_{el}	up to 87.4%	possible after purification	one engine type ready for 100% hydrogen; other engines to be offered for up to 25% hydrogen
MWM	400 kW_{el} ... 3770 kW_{el}	up to 86.7%	possible after purification	admixture of H_2 with 10% possible without technical modifications; with new gas engines or retrofit, possible to use fuel with up to 25% H_2
MAN	68 kW_{el} ... 750 kW_{el}	up to over 90%	no specific mentioning of CO_2 fertilization	certain types designed for hydrogen at 20% without modification
mtu	250 kW_{el} ... 1950 kW_{el}, 50 Hz	up to 87.9%	possible after purification	some series can be operated with 25% hydrogen; some series under development for use with 100% H_2 in 2023

The Jenbacher gas engines can be operated with various fuels, with natural gas, flare gas, propane, biogas, landfill gas and sewage gas, coal mine gas, coke/wood/pyrolysis gas. A Jenbacher Type 4 engine can also be run on special gases as e.g. wood gas and pyrolysis gas. The engines operate at a range of electrical power from 249 kW to 3360 kW for biogas, and reach a thermal output from 266 kW to 3070 kW in the different engine types. The electrical efficiency is from 39.1% up to 44.8%, and the thermal efficiency from 40% to 49.5%. The engines are available with 8, 12, 16 or 20 cylinders, and for 50 Hz or 60 Hz. CO_2 from the engine exhaust gas can be used in greenhouses. The exhaust gas is cleaned with special catalytic converters (SCR and oxidation catalytic converters), and cooled down by a heat exchanger. It is pointed out that efficient operation is possible for greenhouses that are 1 hectare or more in size. CHP or cogeneration modules by INNIO Jenbacher are available as containerized solutions, or they can be installed inside buildings. Moreover, the Jenbacher Type 4 engine is stated to be available for use with 100% hydrogen. The other gas engines can be offered for running on up to 25% hydrogen, or as special versions of some types for up to 60% hydrogen admixed to natural gas. (INNIO Jenbacher 2021)

MWM gas engines can be operated with various fuels, natural gas, biogas, landfill gas, sewage gas, shale gas, mine gas, coke oven gas and syngas. Engines are available with 8, 12, 16 or 20 cylinders, and for 50 Hz or 60 Hz. The electrical power output for engine types for biogas applications ranges from 400 kW to 3770 kW, and the thermal output from 394 kW to 3196 kW. The electrical efficiency is given with 43% to 43.6%, and the thermal efficiency from 40.6% to 44.1%. Efficiencies are for biogas 60% CH_4, 32% CO_2, and rest N_2, and a minimum heating value of 5.0 kWh/Nm^3. The exhaust gas can be treated by SCR catalysts to reduce NO_x emissions and with oxidative catalysts to reduce carbon monoxide and then be used as carbon fertilizer in greenhouses. Container modules are available for gas engine series TCG 3016, TCG 3020, TCG 2020. Containers offer the biogas genset, cooling water and exhaust gas heat exchanger, special gas preprocessing system. MWM gas engines can be operated with an admixture of 10% hydrogen without technical modifications. For new engines or retrofit, it will be possible to use fuel with up to 25% hydrogen. (Caterpillar Energy Solutions 2022)

MAN gas engines for use in cogeneration systems can operate on natural gas or special gases such as biogas, landfill gas or sewage gas. Engines are available for 50 Hz or 60 Hz, and with 4, 6, 8, or 12 cylinders. Electrical power for special gas engines ranges from 68 kW_{el} to 750 kW_{el}, and efficiency is stated to reach over 90%. SCR catalytic converter is available. Certain engine types can be used with up to 20% hydrogen admixture without modification. (MAN 2022)

Gas generator sets “mtu” by Rolls-Royce Power Systems AG can be fuelled with natural gas, liquid propane or biogas. Generator sets are available for 50 Hz or 60 Hz, and with 6, 8, 12, 16 or 20 cylinders. The electrical power ranges from 250 kW_{el} to 1950 kW_{el}, with a total efficiency of up to 87.9%. Systems can be built into containers. Application of CO_2 in greenhouses possible after cleaning the exhaust gas. Some gensets are already ready for use with 25% hydrogen, and Rolls-Royce states that starting from 2023, there will be engines available for use with 100% hydrogen. Also engine conversion will be possible. (Rolls-Royce 2022)

Natural gas and CHP systems are used in greenhouse horticulture in, for instance, the Netherlands and the United Kingdom. According to estimations, two thirds of growers use CHP systems in the UK, and some growers use the generated electricity for LED lighting. Those who do not, export electricity to the grid. The usual CHP capacity is between 0.75 to 1 MW_{el}/ha. (Alberici et al. 2017)

In 2019, natural gas made a share of 78% in the energy supply of greenhouse horticulture in the Netherlands while it was even 88% in 2010. CHP systems were used on about 62% of the greenhouse area in 2019, with a total capacity of 2 550 MW_{el}. About 74% of the total energy consumption was in the form of heat and 26% in the form of electricity in 2019. Growers produced more than half of the electricity (58%) themselves by cogeneration of heat and power. The remaining 42% of electricity was bought. While electriciy consumption was in total approximately 8 billion kWh in 2019, total electricity production was appoximately 10.5 billion kWh. More than half of the produced electricity (56%) was sold and the remaining amount used in the greenhouse operations. Of the energy consumed in 2019, 9.4% were renewable energy, and geothermal energy was the most common among the renewable sources. The total greenhouse area in the Netherlands was about 9 500 ha in 2019. (Van der Velden & Smit 2020)

Choice of a CHP will depend on the individual energy demands of any given greenhouse, the area and crop cultivated. Seasonal and daily heat and electricity demand and consumption varies. In greenhouses with artificial lighting, a lot of heat energy is coming from the high-pressure sodium lamps. During lighting, the demand for heating is less than when lamps are not on. Heat accumulating tanks can be used as buffers. An exemplary illustration of the seasonal heating demands of a Finnish greenhouse is shown in Figure 48. Cogeneration of heat, electricity and carbon dioxide is practicable in the months when heating of greenhouses is needed. Other energy consumers would be needed, if cogeneration of heat and electricity were to be continued over the summer months.

Figure 48. Seasonal representation of energy requirements in Finland. Reproduced from Tataraki et al. (2020) under a Creative Commons Attribution license (CCBY 4.0).

Examples of greenhouse enterprises using biogas

Turakkalan puutarha Oy in Eastern Finland produces potted herbs on an area of 7 000 m^2. The greenhouse company receives biogas from a neighbouring biogas plant, Juvan Bioson Oy. Turakkalan puutarha combusts the biogas in a CHP plant. Heat can be stored in a heat accumulator. About one third of the enterprise's energy demand can be covered by the biogas. The greenhouse company uses also a wood chip system. The biogas plant is mainly owned by 12 farms (egg producers, organic and ordinary dairy farms) and Turakkalan puutarha. The substrate consists of cow manure sludge, chicken manure and some material from food industry. A total of 600 000 to 800 000 m^3 of biogas are produced per year, equivalent to 2 000 – 3 000 MWh of energy. Biogas is also used to cover the biogas plant's heat requirements. (Juvan Bioson Oy 2022)

The Westhof Bio-Gemüse GmbH & Co. KG in Northern Germany cultivates organic vegetables in fields and greenhouses. The total agricultural area is 1 000 ha, and is cultivated in a 6-years crop rotation. The main products from the fields are carrots, cabbage and peas. Tomato and pepper is cultivated in two greenhouses. The greenhouses comprise in total 10 ha, located in the towns of Hennstedt (6 ha) and Wöhrden (4 ha). At the Wöhrden site, a biogas plant was built in 2014. The plant utilizes the waste from the field crop rotations (clovergrass, cereals, wild flowers) and vegetable waste from the production. The digestate from the biogas plant is used as fertilizer on the fields. At both greenhouse locations, boilers and CHP units have already been used for the production of energy. In 2020, the systems were renewed with six CHP units at the Hennstedt greenhouse (total of 7 800 kW electrical power). These are run with biomethane and cover the entire electricity and heat demand. The electricity is fed to the grid according demand.

In Wöhrden, two CHP units (2000 kW and 3360 kW) were added to the existing two systems. Carbon dioxide from the exhaust gases is used as carbon fertilizer in the greenhouses. Buffer storages are in use at both sites. (Westhof Bio 2022) The CHPs in Wöhrden and part of the CHP units supplied in Hennstedt in 2020 were delivered by 2G-Energy AG. Through a subsidiary, 2G-Energy offers the opportunity to rent or lease CHPs.

4.6.5 Investigating the possibilities to use carbon dioxide from biogas upgrading as fertilizer in greenhouse cultivations

Carbon dioxide is used as a gaseous carbon fertilizer in greenhouses to improve crop growth and yield (Heuvelink 2005). Carbon dioxide enrichment has also been associated with other beneficial effects such as for instance increasing red leaf lettuce's flavonoid glycoside concentrations, which can be health promoting (Becker et al. 2016).

Means of carbon dioxide supply to greenhouses include:

1. Technical grade (liquid) carbon dioxide
2. Combustion of natural gas or LPG on-site
3. Carbon dioxide capture and utilization from industrial operations

Carbon dioxide is either fed to the greenhouse as pure technical grade carbon dioxide from carbon dioxide tanks or it can be produced by burning natural gas or propane gas (LPG) to produce heat and carbon dioxide. Burning of either of the gases also introduces heat and water vapour into the greenhouse (Peet & Welles 2005); this might not always be wanted.

Present ways of using carbon dioxide in greenhouse cultivation

Today, the normal carbon dioxide concentration in the air lies at 400 ppm. Enriching the greenhouse air to a level of 750-800 µmol/mol (ppm) can increase yields by up to 30% (Peet & Welles 2005). Carbon dioxide is being fed to greenhouses during day time or when greenhouses are artificially lighted. Whenever there is the need for ventilating the greenhouse, addition of carbon dioxide is either reduced (up to a set intensity of ventilation) or discontinued when ventilation is more intense as the set point. Also light levels can be taken into account when planning carbon dioxide addition with higher concentrations on sunny days and lower concentrations on cloudy days. Carbon dioxide concentration in the greenhouse can be monitored with sensors. Since carbon dioxide is assimilated in plant photosynthesis, the natural (normal) carbon dioxide level of 400 ppm is being reduced in well insulated greenhouses during the day. Therefore, carbon dioxide addition might be necessary even to simply keep up the level at 360-400 ppm.

When adding carbon dioxide, job safety of workers has to be taken into account. The admittable carbon dioxide concentration of on average 5 000 ppm per hour (or 9 100 mg/m^3) for a 8 hours time average must not be surpassed (Sosiaali- ja terveysministeriön asetus haitallisiksi tunnetuista pitoisuuksista 654/2020, 883/2021). The maximum concentration for plants is species specific, where vegetables tomato and cucumber can handle higher carbon dioxide concentrations than for instance ornamental plants (BDEW 2018).

Carbon dioxide can be added to a greenhouse cultivation at a concentration of for instance 7-20 grams per m^2 per hour (Andersson 2010). It was reported by Qian et al. (2011, referred to in De Gelder et al. 2012) that a carbon dioxide concentration of 1075 µmol/mol could be maintained with the use of 14 kg/m^2 CO_2 in a closed greenhouse, while in an open greenhouse, 55 kg/m^2 CO_2 were required to maintain a CO_2 concentration of 772 µmol/mol on average during the day. In both greenhouses, the CO_2 supply was 23 g/(m^2*h). A closed greenhouse is a greenhouse with cooling technology other than through ventilation by roof windows.

According to an example by Air Liquide (2022), a German tomato greenhouse with a size of 11 ha can consume up to 3 000 tonnes of carbon dioxide yearly, which translates into a consumption of 27.3 kg CO_2/m^2. In the example greenhouse, the carbon dioxide is stored in liquid form in a 50-ton tank with special insulation and transformed into gas in two vaporizers. Up to 4 000 kg gaseous CO_2 can be produced per hour. Concentrations of 0.06 to 0.12 vol-% are considered optimal for carbon dioxide fertilization.

Based on a survey made by Novia University of Applied Sciences amongst greenhouse enterprises in Ostrobothnia in 2010 (Borg 2011 b), 45% of the companies answered that they used carbon dioxide gas, and 38% of the companies reported that they used LPG to produce carbon dioxide. Not all the 82 responding companies gave the amounts they used, but from the given answers it was calculated that in total 1.78 million kg carbon dioxide gas were used by 30 growers, and 1.9 million kg LPG were used by 27 growers, respectively. Given a carbon dioxide production of about 3 kg per 1 kg combusted propane (Linde AGA 2022), approximately 5.7 million kilogram carbon dioxide were produced through LPG, three times the amount as fed as carbon dioxide gas. Companies fed carbon dioxide per area at on average 12 kg/m^2 (total area of 14.4 ha) and used on average 14 kg/m^2 (total area of 13.2 ha) LPG to produce carbon dioxide. Bigger greenhouses used more CO_2 per m^2 than smaller greenhouses. (Borg 2011 b)

It had been previously reported for Finland in 2004, that about 4.2 million kilogram of technical grade carbon dioxide had been fed to greenhouses, and additional carbon dioxide had been produced by combusting approximately 1 million kilogram LPG, 660 thousand litres of light oil, and 3 300 m^3 of natural gas. (Hiltunen et al. 2005)

The annual consumption of CO_2 in greenhouses in the Netherlands is estimated to be between 5 and 6.3 $MtCO_2$, of which the majority is produced by gas-fired boilers or co-generation systems in the greenhouse enterprises (International Energy Agency 2019). The use of external CO_2 sources has grown in the Netherlands and was about 700 $ktCO_2$ in 2019 (Van der Velden & Smit 2020).

The figures show that there is a considerable amount of carbon dioxide used in greenhouses every year. It appears logic to utilize waste streams from industrial sites, where clean carbon dioxide and heat could be directed to greenhouses. An adequate infrastructure is needed for implementing this approach, with either greenhouses being located in physical vicinity to the respective industrial site, or the existence of a distribution system between heat and CO_2 producer and consumer. Employing carbon capture and utilization in horticulture could even provide a marketing advantage for supermarkets (Alberici et al. 2017). One example of a carbon dioxide distribution network is OCAP CO2 B.V. who operate carbon dioxide capture and distribution business employing a pipeline between industries generating carbon dioxide and consuming horticultural greenhouses in the West of the Netherlands. The 100 km pipeline had originally been an oil pipeline and then been adjusted for carbon dioxide transport. (OCAP 2022) An oil refinery and a bioethanol plant are the industries that generate the carbon dioxide. For 2021, a supply of almost 600 000 tons of carbon dioxide to greenhouses was anticipated (Alcoenergy 2021), and 600 hundred greenhouses are part of the distribution network (OCAP 2022).

Production and use of carbon dioxide

Carbon dioxide is produced as a by-product in many processes: energy production from fossil fuels, from industries such as cement, iron and steel manufacture, from chemical industry, and other (Rodin et al. 2020).

The supply of carbon dioxide is connected to the manufacturing of ammonia and fertilizers. Most carbon dioxide that is generated during ammonia production is being used in urea production, but also sourced for sale. (International Energy Agency 2019) In 2018, 176 Mt of ammonia were produced, which generated about 500 million tons of carbon dioxide. Ammonia is currently synthesised via the Haber Bosch process, and the hydrogen needed in the process is mainly produced through steam reforming of methane. (The Royal Society 2020)

Supply and demand do not always match, as experienced in the food and beverage industry, since fertilizers are usually manufactured in the autumn and winter, while demand for carbon dioxide in the food industry is usually high in the summer months. (International Energy Agency 2019) In autumn 2021, it had been reported that some fertilizer plants in Great-Britain had shut down because of the high price for natural gas that was used as energy source in the process. As a consequence, the production of carbon dioxide went down with effects on the food industry in Great-Britain. It was anticipated that the price for carbon dioxide would rise to 400%. (Reuters 2021)

The price for carbon dioxide is not global, but depends on region and industry (International Energy Agency 2019). For instance Chemanalyst (2022) reported that the price of liquid carbon dioxide was recorded at around USD 390/MT (372 EUR) at the end of June 2022 in the European markets. Due to high energy prices, various fertilizer manufacturers had suspended their operations in Europe. In addition, demand for dry ice in the food industry added to the price development.

Carbon dioxide can be used in many industries today, either in direct use or in conversions into other products. Carbon dioxide is used in metals fabrication, fire extinguishers, cooling, health care, food industry to fizz beverages or as a sealing gas also in combination with nitrogen in food packaging, and as carbon fertilizer in the greenhouse cultivation industry. Carbon dioxide can be converted into fuels (methane, methanol, gasoline/diesel or aviation fuel), chemicals (e.g. intermediates methane and methanol, or polymers), or building materials (filling, cement or concrete). Global demand for carbon dioxide was estimated to be 230 million tons in 2015. Urea manufacturing consumed 57% and enhanced oil recovery (EOR) 34% of that amount of carbon dioxide. The production of carbon dioxide for EOR involves to a large part geological sources. (International Energy Agency 2019)

Capturing carbon dioxide from biogas

Raw biogas consists of mainly methane and carbon dioxide in slightly variable proportions and it contains water vapour and other gas compounds. Typical values are (55-)65% for methane and (45-)35% carbon dioxide (Andersson 2010, Öling-Wärnå 2019). The exact consistence varies depending on the feedstock that is used in the process. In cases where biogas is cleaned to biomethane for transportation grade or injection into the gasgrid, the carbon dioxide is separated from the biogas in an upgrading facility. During the cleaning process water vapour and hydrogen sulphides are removed from the biogas. In the upgrading process carbon dioxide is separated and the energy density is thereby increased. As a result a methane concentration of more than 95 % is reached (Deublein and Steinhauser 2011). This gas is referred to as biomethane.

There are several technologies available to upgrade biogas: pressure swing adsorption (PSA), physical absorption with inorganic solvents, physical absorption with organic solvents, chemical absorption with inorganic solvents, chemical absorption with organic solvents, high-pressure membrane separation, low-pressure membrane separation, and cryogenic upgrading (Beil and Beyrich 2013). The raw biogas is either cleaned prior to the upgrading or cleaning is integrated in the upgrading process.

From the upgrading facility, the carbon dioxide is usually released into the air. This carbon dioxide is called biogenic, since it originates from the digestion of biomass in the first place and therefore can be considered carbon neutral, if the released carbon dioxide is to be bound in carbon sinks (plants, soil, oceans) later. Nevertheless, utilization of carbon dioxide from biogas production could be considered in the long run, in order to reduce impact on the climate. Life cycle analysis is needed to ensure that this is really the case.

Technology

Research results have shown that carbon dioxide captured from a biogas production facility in Northern Italy in a methane/carbon dioxide membrane separation was complying with food grade requirements (Esposito et al. 2019). The biogas plant has the capacity to digest 400 000 tonnes of biomass per year of organic urban waste in a thermophilic process. It can treat biogas at a rate of 6250 m^3 h^{-1}. After the initial purification including water scrubbing, desulphurization, removal of VOC, compression, and coal purification, the gas is fed into the separation process at a pressure of 13-16 bar. In the separation, the gas stream passes through three membrane modules. The membranes consist of polyimide hollow fibre modules of 1.3 m length. The diameter of the fibres was 0.5 mm and there were several tens of thousands of them. Methane is mainly retained, while carbon dioxide passes through the membranes. Two modules one after the other produce the methane rich part; the carbon dioxide permeate from the first module is sent to a third module in which almost pure carbon dioxide is produced. This carbon dioxide is then processed further by liquefaction, compression, drying and purifying. Carbon dioxide and non-condensable gases (nitrogen, oxygen and methane) are separated from each other upon cooling to -30 °C. In a subsequent step of distillation and condensation, carbon dioxide reached such chemical purity (99.9 vol%) that it complied with food grade quality according to EIGA/ISTB standard (standard of European Industrial Gas Association and the International Society of Beverage Technologists). (Esposito et al. 2019)

Linde is providing carbon dioxide purification and liquefaction plants in modular units for capacities from 30 to 360 metric tonnes per day, and customized plants for bigger capacities. The process includes pre-cooling and compression, scrubbing, drying and adsorption, liquefaction and storage. In the first step, the feed gas is cooled down and water is separated. Then the gas in compressed, and washed and cooled in the scrubber. Water and traces of chemical components are removed in the dryer. Additional adsorbers and filters can be installed. The liquefaction is done with a reboiler and carbon dioxide distillation column. Pressurized tanks store the liquefied carbon dioxide. From here, it can be pumped to different means of transportation (e.g. trucks, ships). (Linde 2018)

Cryogenic biogas upgrading could combine CO_2 recovery in liquid form in the same process with biogas liquefaction (cf. pages 13–14 this report: Cryogenic biogas upgrading and liquefaction).

Potential volumes and costs

Rodin et al. (2020) assessed the biogenic carbon dioxide potentials in Europe for valorization. The authors presented that the amount of carbon dioxide from biomethane production (biogas upgrading) in the European Union EU-28 member states in 2016 was calculated to be 3.14 Mt/year. For the EU-28 that same year, the carbon dioxide potential from biogas production was estimated to be 20.01 Mt/year. Summed up, this could result in a total potential of 23.15 Mt/year. An estimated total of 69.7 Mt/a of CO_2 are being produced by biogas upgrading, biogas combustion and ethanol and other fermentation processes. These sources together still add up to only a small proportion of CO_2 in comparison to an estimated total of 910 Mt/year emitted from the energy industry in power and heat production from fossil fuels.

In 2017, a total of 172 million m^3 biogas were produced in Finland (Ministry of Economic Affairs and Employment 2020). Mutikainen et al. (2016) forecasted that in Finland in 2030, there might be a total of 930 million m^3 biogas in the transport sector and a volume of 1.2 million tonnes of CO_2. These figures would translate to a potential revenue worth 837 million Euros for transport biogas and 240 million Euros for carbon dioxide based on an anticipated price of 200 Euros per tonne carbon dioxide (Mutikainen et al. 2016).

Carbon capture costs have been estimated to range between USD 15-25/t CO_2 for processes that produce highly concentrated CO_2 streams. These are for instance ethanol production and natural gas processing. In applications where diluted CO_2 streams are produced, the costs can range between USD 40-120/t CO_2. Examples of such industrial processes are cement and power generation. Carbon dioxide can also be captured from the air, and this is the most expensive technology. For the United States, the cost of onshore transport by pipeline is estimated to be between USD 2-14/t CO_2. The onshore storage can be available at a cost of below USD 10/t CO2. (Baylin-Stern & Berhout 2021)

The costs for CO_2 capture from biogas upgrading have been reported to range from 5-9 EUR/t CO_2 and 0-90 EUR/t CO_2, as compiled in Rodin et al. (2020).

Evidently, profitability of capturing and liquefying carbon dioxide from biogas plants depends on product quality, volumes and price in the respective (regional) market.

Example cases

Carbon dioxide capture at biogas production facilities is implemented or in the stage of planning at several facilities in Europe. Some examples are presented in the following.

Denmark

Danish Nature Energy and partners own and operate 12 biogas plants in Denmark, and one in France. In 2022, the plants are expected to treat more than 4.4 million tons of biomass and convert this biomass into 181 million m^3 of biogas (Nature Energy 2022). The Korskro biogas plant close to Esbjerg was inaugurated in 2019. Approximately 1 million tonnes of biomass, agricultural waste, are processed per year. 85% of the biomass is livestock manure from cattle, pigs and mink. The remaining biomass consists of organic waste from industry and retail, energy crops and litter from livestock stables. The biogas plant produces about 49 million Nm^3 biogas per year. After upgrading, the biomethane is injected into the natural gas grid. (Bioenergy International 2019; International Energy Agency 2020)

Danish enterprise Strandmøllen A/S has built a carbon dioxide facility at the Korskro biogas plant. Carbon dioxide is purified in several steps: filtering, washing, distillation, compressing, condensation, drying and cooling. (International Energy Agency 2020) The resulting carbon dioxide that is separated in the upgrading process complies even with food grade. The product is complying with standards by ISBT (standard for terminology, identification, coding and labeling of medical products of human origin) and EIGA (European Industrial Gases Association). According to Strandmøllen A/S, the carbon dioxide is suitable for use in steel – and engine industry, the health sector and pharmaceutical industry. (Strandmøllen A/S 2022)

Denmark is importing approximately 65 000 tons of carbon dioxide per year. This carbon dioxide is typically produced in the fertilizer industry and based on fossil energy. The carbon dioxide facility at Korskro can produce 16 250 tons carbon dioxide, or 25% of Denmark's annual carbon dioxide consumption. The capacity for carbon dioxide purification at Korskro is still slightly higher. (International Energy Agency 2020)

United Kingdom

Bright Biomethane constructed an upgrading plant to a biogas plant in Hereford in 2016. The biogas plant uses cattle manure, chicken manure, apple pomace, and maize silage to produce biogas. The raw biogas has a concentration of 50-55% methane. The biogas is upgraded to biomethane for injection into the national grid with an estimated volume of 4 million Nm^3 biomethane per year. The upgrading plant has a capacity of 1 000 Nm^3/hr raw biogas and 520 Nm^3/hr biomethane. The methane concentration in the product gas is over 97%. There is a liquefaction capacity of 850 kg/h at the plant. The resulting carbon dioxide has a purity of 99.97% and meets food grade. (Bright Renewables B.V. 2022)

UK based company BioCarbonics Ltd sells liquefied carbon dioxide from biogas upgrading processes to customers in food and drink industry. The ambition of the company is to provide a more reliable supply model for the CO_2 industry in the UK by utilizing multiple smaller sources of carbon dioxide from biogas plants' biomethane production for injection into the natural gas grid. (BioCarbonics 2022) This way, dependency on carbon dioxide recovery from ammonia production plants can be alleviated.

Switzerland

In spring 2022, enterprise CO_2 Energie AG initiated building a liquefaction facility at the Nesselnbach biogas plant. The biogas plant produces biogas equivalent to an energy content of 25 GWh. About 90% of the carbon dioxide will be captured, i.e. up to 3 000 tons. In the process, the carbon dioxide will be cleaned, filtered, dewatered under pressure, cooled to -24 °C, and stored in tanks. Swiss enterprise Messer Schweiz AG will sell the gas on the national market for industrial applications, drink industry or medical technology. The construction comprises a ship container-sized center piece, two washing towers of 12 meter height and half a meter diameter. The gas will be stored in 2 twelve meter high tanks. (Swisspower 2022)

Other opportunities of utilizing carbon dioxide

Carbon dioxide can be employed in the synthesis of gaseous and liquid fuels or chemicals. Examples of enterprises implementing synthesis processes are given here.

Q Power (Finland)

Q Power offers solutions for biocatalytic methanation and gasification and syngas upgrading. The production of methane from hydrogen and carbon dioxide is undertaken in bioreactors employing originally Finnish marshland microbes. The microbes act as the catalyst at low temperatures (50 to 70 °C) following the Sabatier reaction. The process efficiency is said to be 82%. Q Power offers modular systems from 50 kW up to 20 MW.

The gasification process is able to transform lignin-rich materials, sewage sludge and plastics into synthesis gas. Synthesis gas contains carbon monoxide, hydrogen and carbon dioxide. The gasification operates at temperatures higher than 1 000 °C. In a subsquent upgrading reactor, carbon monoxide from the syngas can be transformed into carbon dioxide and hydrogen. Even here, Q Power employs micro-organisms under anaerobic conditions and at ambient temperature and pressure. The process is patented. Carbon dioxide and hydrogen are then fed into the biomethanation process. Q Power offers solutions from 250 kW up to 20 MW. (Q Power 2022)

Carbon Recycling International CRI (Iceland)

The Icelandic company Carbon Recycling International produces renewable methanol from CO_2 and H_2. The facility was built in 2012. In the facility, carbon dioxide is captured from flue gases of a geothermal power plant and purified. After compression, hydrogen containing synthesis gas produced by electrolysis reacts in a catalyzed reaction with carbon dioxide. The product is then purified and water is removed by distillation. The plant converts 5500 tons CO_2 into 4 000 tons methanol per year.

CRI has several projects ongoing. The goal at the first commercial plant, the Shunli plant in China, is the production of 110 000 tons methanol from 160 000 tons CO_2. The plant is positioned close to a coke oven gas production facility. Carbon dioxide and hydrogen are the main by-products of the coke oven gas production. The end product is called “vulcanol” and sold in Europe and China. According to CRI, the product reduces carbon dioxide emissions by more than 90% as compared to gasoline or diesel. (Carbon Recycling International 2022)

4.7 Summary and conclusions

Biogas offers a viable alternative for industrial operators to meet their emission targets. However, to make biogas a realistic option for industry, the production and supply of liquefied biomethane in particular needs to be increased. Furthermore, the integration of LBG into industrial energy systems requires a stable and predictable operating environment and assurance of the continued availability of fuel. Therefore, the study focused on investigating biomethane availability, especially the availability of LBG. In addition, a comprehensive survey of industrial fuel prices was done, including price forecasts until 2040. Based on the study, the following conclusions could be made:

- LBG supply may be an issue, as the availability of liquefied biomethane is currently quite limited.

- However, interest in liquefied biomethane is growing, and several LBG projects are underway in Finland. After completing these projects, the Finnish LBG production will triple from the current level.

- With rising fossil fuel prices, renewable energy sources are expected to become increasingly competitive with fossil fuels.

Another potential new user of biomethane investigated in this study was the waste-to-energy sector. The modification needs in burner technology related to fuel switching as well as various gas storage options were examined from both technical and economic perspectives. The greenhouse gas benefits of fuel switching were also assessed. The study showed that:

- When comparing total investment costs, the LBG option appears more advantageous.
- However, in the case of liquefied gas, the management of boil-off gas associated with intermittent gas use poses challenges. Extended storage times may also degrade LBG quality.
- Biomethane could be a part of a regional strategy for reducing GHG emissions from the energy sector.

With respect to the question whether the greenhouse industry could be part of a circular economy with biogas, the following can be stated:

- The biomass waste from tomato and cucumber cultivations can be employed as substrate in preferably co-digestion with other substrates to produce biogas.
- The estimation for annual biomass waste ranges from around 7 000 to 10 000 tons for tomato and at least 5 000 tons for cucumber in the region of Ostrobothnia. The range for cucumber waste was much larger than for tomato. An estimated biogas energy content of 4.3 MWh could theoretically have been produced from the biomass waste in 2021. Only tomato and cucumber wastes have been estimated here, but there is additional plant waste from other vegetable and flower cultivation.
- The total energy consumption by the Finnish greenhouse industry was 1.7 TWh in 2021. The proportion of energy production from renewable sources has increased continuously since 2006, and has contributed to 56% of the heating energy in 2021. Hence, the Finnish greenhouse industry uses already a fair amount of renewable bioenergy in heating.
- There are numerous manufacturers of gas engines and cogeneration systems for use with biogas. Some of the gas engines are already compatible to admixture of hydrogen. Thus with these engines, there would be readiness for utilization of hydrogen even in the near future.

- For greenhouse enterprises to be able to utilize biogas in their operations at this point, investments would be needed in CHP applications and biogas storage systems.

- Carbon dioxide from biogas production facilities can be captured and liquefied. The product can meet quality requirements for food-grade quality and is therefore usable in a multitude of applications. However profitability of capture might depend on the regional market.

- There are several examples of projects and operations that are already installed or going to be installed at biogas production facilities in Europe to capture and liquefy carbon dioxide to be sold.

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5 DIALOGUE MECHANISMS AND COMMON OPERATING MODELS

Petra Berg and Aino Myllykangas

To enable a rapid development of the biogas sector there is a need to understand supply and demand and to bring them together. The market uptake of biogas solutions has long been characterized by the so called “chicken or egg dilemma”, where production and consumption have not met. In other words, the lack of biogas availability hasn’t encouraged investments in gas-powered vehicles or facilities, nor has the lack of users encouraged furthering biogas production or distribution.

As a solution to the above-mentioned biogas-dilemma, a “collective agreement” has been proposed (Knuts et al. 2020), in which it is generally and jointly decided to invest in activities. According to Sitra (Mutikainen et al. 2016), the breakthrough of biogas requires “an understanding and development of the biogas industry as a whole from the availability and utilization of raw materials for various end-product uses and the closure of material cycles”. This means both the creation of new common operating models and networks for a win-win situation as well as research-based information, which provides answers to uncertainties and builds a clear picture of the activities required for the use of biogas. Success also requires the creation of common market dialogue mechanisms that consider the needs of the different members of the network.

One of the main tasks in work package 4 was to establish dialogue mechanisms between actors in Ostrobothnia and beyond, who have the capability to contribute to accelerating the development of more biogas solutions in the region. Based upon the dialogues that occurred in the three workshops organized by the project as well as expert interviews, common operating models were drafted. Thus, as the outcome of the other main task, common operating models are presented as descriptions that illustrate the actors and functions needed to bring about the desired change. They are based on an understanding of the needs of biogas users, the ability of producers to meet those needs and the so-called role and potential of third actors to create structures that allow for change.

This chapter first (5.1) gives an overview of the current state of biogas in Ostrobothnia, based upon the knowledge gathered through expert interviews, earlier research and reports. Secondly (5.2) it presents the process of creating dialogue mechanisms through workshops and the scenario work that was utilized. Here, the techno-economic calculations from the earlier, technical work packages were used to suggest three possible development scenarios for more biogas solutions in the region. Also, the connection of waste management and transport to the biogas sector was explored. Thirdly (5.3), based upon the findings from the workshops and earlier research, the key biogas actors of the

Ostrobothnia playing field were mapped and a suggestion for common operating models made. Finally, the fourth part (5.4) summarizes the outcomes of work package 4.

5.1 Current state of Biogas in Ostrobothnia

This section summarizes the earlier findings from the current state analysis and interview analysis (Yorke et al. 2021) as part of work package 4.

Ostrobothnia has over 30 years of experience in the production of biogas. As stated earlier, there are currently two biogas plants in the region, Stormossen in Korsholm and Jeppo Biogas in Jepua. There are also five gas filling stations situated in Vaasa, Korsholm, Jeppo, Pietarsaari, and Vöyri. Overall, the development of the biogas sector in Ostrobothnia has reached a point where the use of gas has become more widespread to the extent that, for example, the purchase of a gas vehicle is a realistic option both as an environmental act and for one's own finances. The pressure of climate change and the need to secure national energy security (move away from dependency on imported fossil fuels) is also making new user groups consider renewable, environmentally friendly alternatives.

Data about needs, value creation, and critical factors of biogas sector actors were collected through a set of 17 semi-structured interviews. The interviewees were selected as they operate within the biogas industry. Most of them hold different roles along the biogas production value chain in Ostrobothnia. The interviewees covered, e.g., biogas producers, representatives of industry and logistics companies, municipalities, and local development companies. Few actors outside of the Ostrobothnia were interviewed to obtain expert knowledge and examples. The interviewees were selected based on an initial list created by the project team, named persons during interviews, and electronic sources describing biogas ecosystem examples.

It has been suggested that the area could foster its development by building a common plan regarding biogas production and distribution. (Knuts et al. 2020). Based on the interviews conducted in the project, it seems that different organizations in the region are not particularly aware of each other's day-to-day activities and circumstances. Hence, it could be useful for actors to interact with each other more, to learn, understand each other and consequently be able to find out about collaboration possibilities. Interviewed actors recognized development possibilities in the sector but they couldn't name the specific directions nor steps towards them. As one interviewee brought up: It could be useful to define a common long-term plan for the biogas sector (or beyond) in Ostrobothnia and then measure its performance.

Generally, the interviewees considered biogas a source of competitivity. Some argued that the adoption of LBG at the local level could result in a competitive advantage for the area of Ostrobothnia. Some also mentioned that from the perspective of the organizations, the companies could develop their sustainability image and act as examples of successful business cases at a global level.

The biogas specific strengths mentioned by interviewees include its nutrient cycle, economic and sustainability impact which shows a shared motivation to develop the sector. Interesting business areas that interviewees were eager to explore included digestate processing into fertilizers, biogas liquefaction for heavy-duty traffic and ships as well as biogas as a source of energy within the industry. Also, localized smaller plants and smart collection of feedstocks were considered opportunities for the regional agriculture to become more circular, boost ecological farming practices as well as provide additional incomes.

The biogas sector in Ostrobothnia has been evolving during the last 30 years which means that there are already key actors networking and taking further steps in the development of new production and distribution facilities. The Stormossen biogas plant, situated in Korsholm, is owned by surrounding municipalities and has been a central actor in the regional biogas market since 1985. Jeppo biogas started in 2013 and is collaborating especially with local agriculture and industry.

In Vaasa, public procurement has had a positive role in the development of the local biogas sector. One project interviewee elaborated that the choice of the city of Vaasa to use biogas buses has provided a reason to build a distribution network to make fuel available. The city of Vaasa has 15 biogas buses in public transport and Korsholm 4 (in 2022), which means that 19 out of 25 buses used in the collective traffic between Vaasa and Korsholm use biogas (Kääriäinen 2022). In the expert interviews, the aim to support renewable energy through public procurement tendering was also mentioned. Another interviewee exemplified this through the environmental management company Remeo which has biogas trucks that make them competitive in cases of public procurement. In the first workshop and during the interviews (Yorke et al. 2021), taxis were introduced as potential users of biogas in the future.

The recycling company Westenergy plans to increase the use of biogas in its logistics chain. In general, there are many industrial players which could start using biogas, for example some of the largest industrial players in the Vaasa region: Wärtsilä Finland Oy, Alteams Finland Oy, Crimppi Oy, Danfoss, Finnfeeds Oy, Logset Oy, Oy Botnia Marin Ab, Oy Primo Finland Ab, Riitan Herkku Oy, Scott Health & Safety Oy, UPC Konsultointi Oy, VEO Oy. (VASEK yrityshakemisto 2021).

The feedstock sources in Ostrobothnia currently include the industry, waste management and sludge. In addition to household biowaste, feedstock is collected, e.g., from the water treatment facility in Vaasa, and the industry around Jeppo Biogas. Currently, there is no farm level biogas plant in Ostrobothnia. The types of agricultural feedstock available in Ostrobothnia includes greenhouse produce, potatoes and pig manure (Ruokatieto 2021). There is growth potential in increasing the use of feedstock from agriculture in the region.

According to the interviews, feedstock is either collected by waste management companies or by the feedstock provider themselves. Logistic costs are usually paid by the feedstock provider. In addition, it was brought up that feedstock providers have municipal agreements stating to which biogas producer they have to deliver the feedstock such as, in the case of households. One interviewee highlighted that when this is not the case, the logistical partner selects the most cost-effective choice available considering pricing and physical distance to the plant. Another interviewee mentioned the diversity of biogas producers as some biogas producers may accept feedstock free of-charge while others collect gate-fees to be paid by either the logistical partner or the feedstock provider (Yorke et al. 2021).

An area that has potential for improvement is the use of digestate as fertilizer through processing. There is already some knowledge around this topic and there is potential to develop it (Knuts et al. 2020). The Bothnia Nutrient Recycling project (2022) has been researching how to reuse the digestate, i.e. the residual product of biogas production.

The use of liquefied gas can be attractive to various users. The interviewees mention opportunities for industry users, ships and heavy traffic. Players of the industry and maritime shipping have already agreed to use LNG provided by Gasum (Gasum 2021). Interviewees also consider mixing LNG and LBG more attractive than sole use of LBG as the total GHG emissions are expected to be lower and the mixture has a more attractive price.

In mobility, based on the number of cars in 2019 there will be 10 000 fully electric cars and 2 000 gas cars in Ostrobothnia already in 2030. This would require 100 charging stations and 20 gas filling stations which are estimated to be a total of 9.6 million euros investments. As the volumes and costs are rising, the area could benefit from a shared gas network. Making the decision to use biogas in transportation is a valuable way to be sustainable and competitive in the market. (Knuts et al. 2020)

In all, there are various actors who have an active role in the development of the Ostrobothnian biogas sector. The green transitions and energy crisis also affect the growing interest for biogas solutions in the region and to enable a swift growth of the sector, more collaboration and dialogue is needed.

Table 27 summarizes the actors and their roles in Ostrobothnia. (Yorke et al. 2020).

Table 27. The biogas sector actors and their roles in Ostrobothnia

Biogas sector actors by levels			
Level	**Roles**	**Actors**	
Macro	Public authorities, influential parties and regulation makers.	Lobbyists, industry unions, nation and regional state administration, municipalities and cities.	The cities of Ostrobothnia: Kaskinen, Korsnäs, Kristiinankaupunki, Kruununpyy, Laihia, Luoto, Maalahti, Mustasaari, Närpiö, Pedersöre, Pietarsaari, Uusikaarlepyy, Vaasa and Vöyri. The regional association: Regional Council of Ostrobothnia and local politicians.
		Licensing authorities, land owners, biogas certifiers.	The regional Centre for Economic Development, Transport and the Environment
Meso	Primary producer: feedstock producers, collection and transportation companies, biogas producers, distribution network providers, environment	Feedstock logistics, farms, industry, field cropping, waste management	Waste management companies move the feedstock. The industrial area in Jepua, other biowaste from households, waste water treatment facility, and elsewhere
		Gas transportation and storage logistic partners, Gas network operators, Facility operators and maintenance, Facility owners and builders, distribution centers	In Ostrobothnia gas is transported and stored by the biogas plant owners. They are also the owners and operators of the gas network including the filling stations. They operate by themselves. They may use partners for maintenance and building.
	Secondary actors	Biogas importers, biogas sales place, facility vendors and building companies, car and work engines sellers, capital investors, financiers, consultants and planners, car producers, work engine producers.	Gas as fuel is sold by the producers directly. In case of gas sold as electricity or heat entering the supplier is Gas energy. The facility vendor and building companies are national players. Car vendors are national. Locally Wärtsilä is both a biogas engine manufacturer and an energy service provider. There are also capital investors, financiers, consultants and planners that act nationally.
	Tertiary actors	Educational institutions, technology developers	These include development businesses and academic institutions in the region.
Micro	early customer and end consumer groups	Society, citizens and end user organizations	Ostrobothnia as a forerunner in sustainable energy
		Farms as energy users, households, industrial users, vehicle owners and drivers	Public procurement in Vaasa, public tendering, private vehicles, marine sector, industry, heavy duty traffic.

The next section (5.2) elaborates more upon dialogues and outcomes from the workshops organized by the project.

5.2 Dialogue mechanisms

To promote dialogue, the project organized three facilitated online workshops for the key players in the biogas industry in Ostrobothnia. The first two workshops, held in March 2021 and September 2021, were focused upon the need for further biogas development in the region. The third workshop, held in November 2021, sought to create more understanding about the waste management and transport sector as a means to facilitate the uptake of more feedstock.

The workshops were planned following the transition management approach, a theoretical framework developed by the Dutch DRIFT institute, where the aim is to manage transitions towards common goals by building dialogue and coalitions between key actors (Loorbach 2010). This approach entails an in-depth planning process before the actual workshops as it is important to map and invite key actors who bring in a variety of perspectives and knowledge. Thus, we approached actors from the industry, governance, research & development, agricultural, legislative and transport sectors.

Because of the COVID-19 pandemic, all meetings were held online, using Zoom and its break out rooms for groupwork. All three workshops were built in a similar fashion, and each workshop began with expert speeches that paved the way for group discussions. The speakers were both project team members and external experts, setting the stage for the aim of the workshop. Usually, there was a time slot of 10-15 minutes for general discussion after the presentations. This was followed by working in 2-3 facilitated groups and using the Google Jamboard platform as a collaborative tool. Figure 49 shows an example image of a filled Jamboard from Workshop 2.

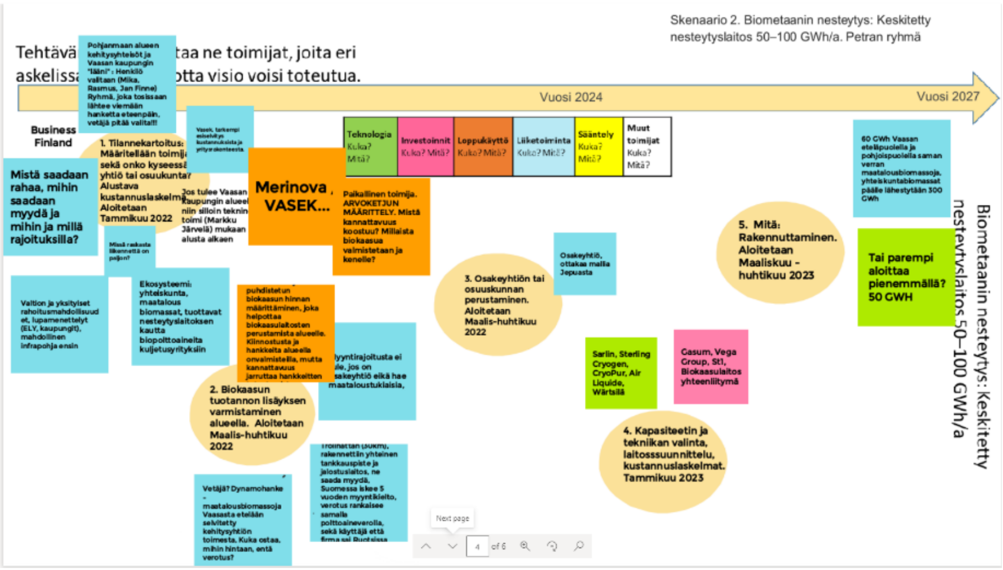

Figure 49. Workshop using the backcasting method facilitated with Google Jamboard (original Finnish version).

The group discussions were held in Zoom break-out rooms. Participants wrote down their thoughts on the topic independently on the Jamboard notes and afterwards they were discussed openly within the group. As part of the process, participants voted for the most relevant actions by marking the preferred sticky notes. Finally, all the groups met in the main Zoom meeting room to present their results to the other participants and discuss the preferred solutions. The workshops were held in Finnish and they were recorded and transcribed for further research analysis. Next, we will elaborate further on the findings from these workshops.

5.2.1 Workshop 1 ”Liquefied biogas hub for Ostrobothnia”

The first workshop titled “Liquefied biogas hub for Ostrobothnia” was held on 25.3.2021. It had 13 participants who represented Jeppo Biogas (biogas producer), Stormossen (biogas producer), Westenergy (waste management company), Wärtsilä (technology supplier/biogas user), Williamsson (biogas user), RL Trans (biogas user), Remeo (waste transport company) and Baltic Connector (pipeline project company).

The first workshop had the aim of discussing the establishment of a biogas liquefaction plant in a central location in Ostrobothnia. During the workshop, the size of the plant was defined as 50-100 or more than 100 gigawatt hours (GWh) per year. The stationary type was considered as the most probable plant type, but a modular/movable plant was also considered as an option. Further, the need for a gas pipeline came up as it might be appropriate to build it at this stage. Another need was to make rural raw materials available and recycled without long transport journeys, and thus small-scale centralized biogas purification and processing also came up for closer scrutiny.

The opportunities brought by the increase in biogas production were seen as environmental impacts, energy self-sufficiency, job creation, utilization of raw materials, building a regional brand, export opportunities, and increasing security of supply. The challenges were price, market readiness, the challenges posed by the monopoly position of the current big (natural gas) market actors, the commitment of the regional players, ensuring continuity and overcoming the challenges of supply and demand, and managing the whole process.

Two core customer actors of the marine sector shipping and freight businesses, Wasaline and Wärtsilä, were identified. Wasaline ship travel from Vaasa to Umeå, Sweden, moving both passengers and cargo. Wärtsilä provides gas engines to the marine sector. This was in line with the findings from the current state analysis, where interviewees stated that the road cargo transport companies might benefit from biogas in the future through the use of LBG (Yorke et al. 2021).

Based on the results from the first workshop, three scenarios were chosen to be developed further in the project. The second workshop of the project was organized around these scenarios and is presented in the next section.

5.2.2 Workshop 2 "Building Collaborative Models to Accelerate the Utilization of Sustainable Biogas"

The second workshop "Building Collaborative Models to Accelerate the Utilization of Sustainable Biogas" was held on 29.9.2021. This workshop brought together 34 participants from various public and private organizations: The Central Union of Swedish-speaking Agricultural Producers in Finland (SLC), University of Vaasa, Österbottens svenska producentförbund r.f. (ÖSP), City of Kaskinen, Gasum, Centre for Economic Development, Transport and the Environment (ELY), City of Vaasa, Jeppo Biogas, Vaasan Vesi, Finnish Safety and Chemicals Agency (Tukes), Nurmon Bioenergia, EPV, Kristinestad, Finnish Gas Association, Vaasa Region Development Company (VASEK), Wärtsilä, Stormossen, Pohjolan Voima, Posti, Dynamo Närpes, Retex, Biokierto, law firm Bird & Bird, and Wasaline.

Based upon the results of Workshop 1, the project team had developed three biogas scenarios:

1) a small scale: centralized biogas purification and processing,

2) a biogas liquefaction: centralized liquefaction hub 50–100 GWh/a, and

3) a regional gas pipeline network.

The working method used to elaborate further on the scenarios is called "backcasting". The idea is to collectively agree upon a goal (in this case the biogas solutions presented in the three scenarios), the timeline for the expected finalizing of the process and then, looking backwards e.g. "from the future towards the current moment", agree upon important steps that needs to be taken. The steps include critical actions and the main actors who should participate in bringing those forwards.

In the second workshop (WS 2), the participants were initially divided into three groups, one for each scenario. They discussed the scenarios using the Google Jamboard as collaborative tool and the groups were facilitated by project staff. In the first step, the participants verified the given scenario, commenting and making changes to the initial suggestion. After they had reached an agreement of the scenario and its timeline (the critical steps), they worked on collaboration models. Here, central actors were added to each step on the timeline. Next the three scenarios are presented separately.

Scenario 1 (SC1). Centralized biogas purification and processing

The first scenario presented two possible options for farm scale biogas production. Here the idea was to find a way to enable scarcely populated, agricultural areas, situated far away from the bigger biogas plants to make use of their feedstock and to receive fertilizers as well as energy in return. Two options were presented:

Option 1. Processing in a movable rubber wheeled unit. The maximum capacity of the mobile unit is 300 Nm^3/h of raw gas. Price estimate for 210 Nm^3/h was 1.7 milj. € (including the container and storage). The transport costs need to be calculated separately. In addition to farm-specific biogas reactors, raw gas storage facilities are needed for the farms.

Option 2. Centralized processing in a stationary processing plant. Transmission of raw gas from site-specific biogas plants in the local pipeline network, eliminating the need for raw gas storage. Processing plant size class> 300 Nm^3/h raw gas. Profitability limit for the pipe ~ 20 km. The price estimate for the centralized plant 420 Nm^3/h + 20 km pipe was 4.3 milj. €.

For both options, the estimated price for farm specific units (raw gas storage) 2 000 MWh/a biogas reactors was 450 000-550 000 €.

The processing plant could be implemented as either a mobile or a stationary plant. In a mobile solution, a common processing unit, e.g. owned by a cooperative, would travel from one farm to another on rubber wheels and clean, refine and pressurize the gas to be transported on to a refueling station or even to a liquefaction plant if one enters the area. An alternative to the circulating unit is a centralized, stationary processing plant to which raw gas would be delivered from the farms by pipeline. A stationary plant would provide more choice e.g. the choice of refining technology and eliminate the need for on-farm gas storage. The challenge with this solution is the cost of the pipe investment, so it is only suitable for fairly short distances. Figure 50 shows the timeline and steps agreed upon by the workshop group.

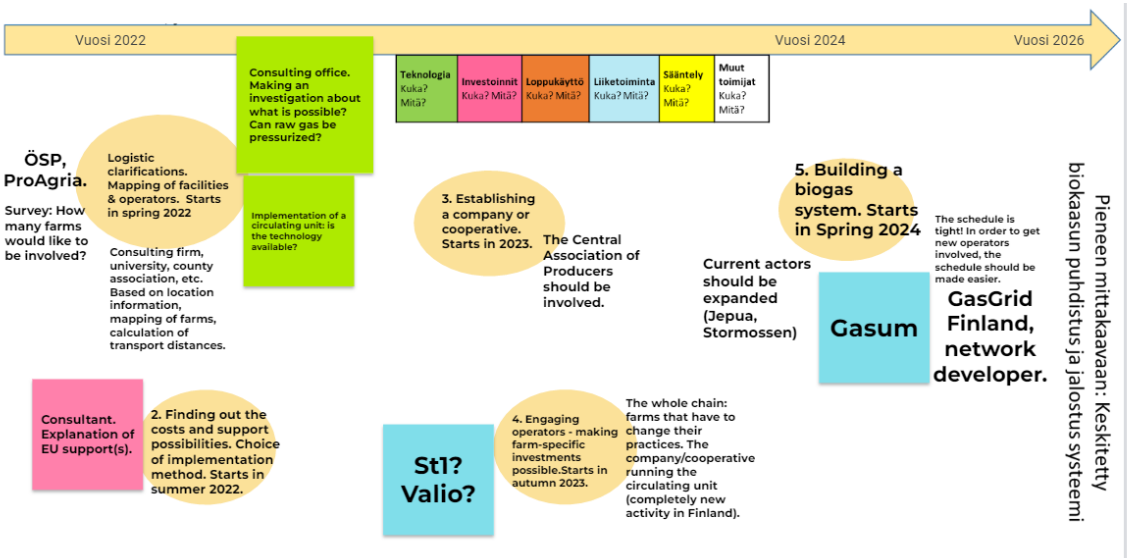

Figure 50. Scenario 1's Jamboard (translated from the original Finnish version).

Initially, the suggestion was that the chosen scenario would be in function 2026, and the work towards the goal would start 2022. During the verification process some of the central steps were set to start later in 2023, but it was seen possible that a regional small scale system could be in function 2026.

Results from the workshop (WS2 SC1) discussions:

The main challenge in farm-scale biogas production is its profitability. If biogas were processed into biomethane, it could be sold as a transport fuel and get the best possible return. The size of the investment is also a problem in small-scale biogas processing. A possible solution to this problem could be a processing plant acquired jointly by several small producers, in which case the costs could be shared.

The workshop mostly discussed the circular option. In addition, it was felt that the proposed timetable was too tight. However, the "vote" between the mobile solution and the stationary solution was almost equal. The need to map out how many farms would be included, to calculate the distances between those farms and to find out who or which group would implement this became important. It was found that the most profitable implementation was only possible on the basis of such surveys and calculations. However, the idea was liked and seen as a possible solution for circulating biomass from wider areas as well.

> *"All actors need to be involved in that (engaging operators, enabling farm-specific investments). It's one value chain and if it's missing a piece, it doesn't work. A business must be born from it. Probably the first starting point, however, are the farms from whose operation the raw material is obtained, which make this possible. They need to change their current ways of doing things. The operator of*

the circulating unit is essential. It is a completely new operator in Finland, there are no such operators at the moment". (Participant in WS2 SC1)

Key actors to take the plans further where namely ÖSP and ProAgria (the Swedish and Finnish-speaking rural advisory organisations), university, municipalities and consultants.

Table 28. Key actors in Scenario 1.

Scenario 1	
Level	**Actors**
Macro	Regional Council of Ostrobothnia, ÖSP, ÖSL, ProAgria, EU Life funding targets, MTK, advocacy companies.
Meso	
Primary actors	Jeppo Biogas, Stormossen, the company/cooperative running the rotating unit, Gasum, Gasgrid, farms (farms' own investments in biogas production).
Secondary actors	Consultant companies, Valio, ST1
Tertiary actors	Universities
Micro	-

During the final group discussion, where all three scenarios where discussed at the end of the workshop, the representative of Finnish Safety and Chemicals Agency (Tukes) clarified that there might be difficulties in receiving permissions for the mobile solution (option 1) as it would not fulfill the safety standards. Thus, option 2, Centralized processing in a stationary processing plant was seen as the most likely option (see Figure 51).

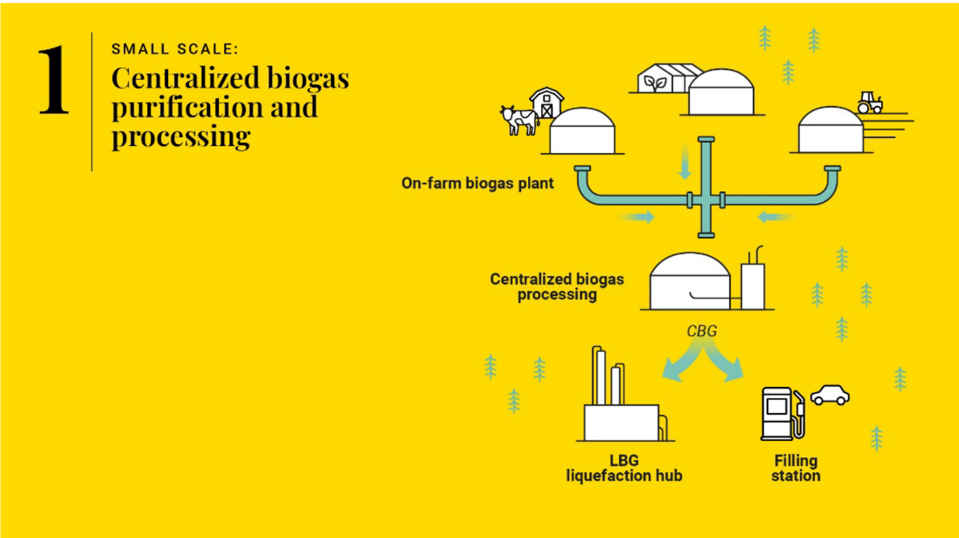

Figure 51. Scenario 1. Small scale: Centralized biogas purification and processing.

As scetched in Figure 51, the raw gas would be delivered from the farms by pipeline. To sum up the findings from scenario 1 we found that both the circulating and stationary options were initially interesting. To put plans to practice would require some time, but the starting year suggested was 2026. First of all, a mapping of farms would be needeed, to know how many would be interested to join and on what incentives? Here the question was who would be the initiating actor(s)? Suggested initiators were ÖSP & ProAgria, University of Vaasa (and other universities), municipalities and consultants. Also, the most cost efficient and profitable solution needs further mapping and calculations. It could also be a viable solution to enable the collection and circulation of biomass from larger areas.

Scenario 2 (SC2). Biogas liquefaction: Centralized liquefaction hub 50–100 GWh/a

The second scenario proposed the liquefaction of biomethane (LBG) centrally in a jointly owned liquefaction plant. Here, transport of biomethane to the plant could either be undertaken by road in container transport or in a regional pipeline network. An LBG filling station could be connected to the liquefaction plant, and for other applications, such as industrial use, LBG would be transported by tanker. The investment costs calculated were 4,5 MEUR for the 50 GWh/a and 8 MEUR for the 100 GWh/a liquefaction plant. The plant would be situated close to the Vaasa and Korsholm industrial areas, maybe somewhere near Stormossen and Westenergy. Figure 52 shows the timeline and steps agreed upon by the workshop group.

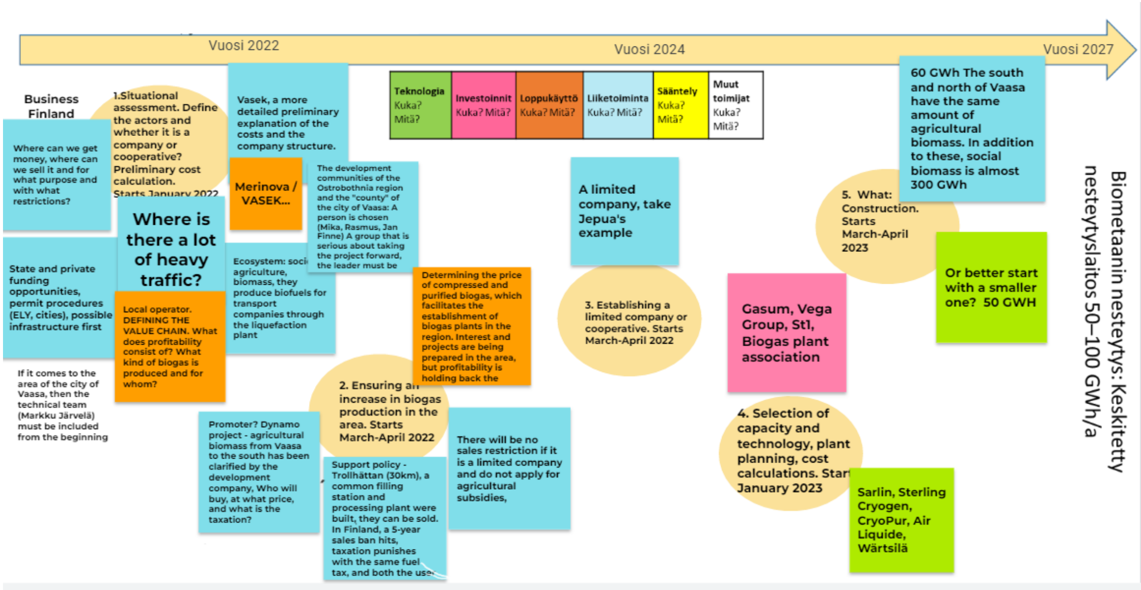

Figure 52. Scenario 2's Jamboard (translated from the original Finnish version)

Initially, the timeline was suggested for the plant to be finalized in 2027. During the verification process, it was agreed that it could be possible if the construction of the plant would be started already in 2023. This means all the steps needed to happen sooner.

Results from the workshop (WS2 SC2) discussions:

Scenario 2's liquefaction plant was considered necessary to increase biogas production and availability in the Ostrobothnia area. The group's opinions were divided between a really large 300 GWh or smaller 50 GWh plant. The year of implementation 2027 seemed possible, but to reach that goal, the milestones were brought forward. The proposed investment costs were seen as too low as implementation is actually more expensive. It was seen as important to form a multi-actor group, which would carry out a preliminary study (definition of the value chain, etc.) and act as an initiator in setting up a limited company. Central to this would be private-public dialogue and cooperation.

> *"This value chain definition started from the fact that when these biogas-producing plants, which take that stuff to the centralized plant there, they would like to know in advance the price at which biogas is now being bought. Well, then again in the value chain it is also important that how much the end customer is willing to pay for liquefied biogas. And who are the end customers? Are they tires, ships, or industry? The entire chain would have to be involved in this in order to determine the profitability of the production, and in that way also to ensure the creation of the production" (Participant in WS2 SC2)*

Initially actors that could be involved in the planning group were named. These are people working with energy and infrastructure development at the city of Vaasa, Korsholm, regional business and development company VASEK, Technology Centre Merinova and Stormossen.

Table 29. Key actors in Scenario 2.

Scenario 2	
Level	**Actors**
Macro	The State of Finland, Ministry of Economic Affairs and Employment Finland TEM, Business Finland, Ostrobothnian development companies (Konkordia, VASEK, Närpes Dynamo ja Kristiinankaupungin Elinkeinokeskus), municipalicities of Vaasa, Kristiinankaupunki, Närpiö. Issuers of Corona Revitalization Fund. If it comes to the area of the city of Vaasa, then the technical committee should be involved from the beginning.
Meso	
Primary actors	Representative of Närpiö greenhouse farms, Gasum, equipment suppliers: Sarlin, Sterling Cryogen, CryoPur, Air Liquide, Wärtsilä, Wega. Operators already have a production plant up and running, biogas consortium.
Secondary actors	ST1
Tertiary actors	-
Micro	-

The idea of the liquefaction hub is the liquefaction of biomethane in a centralized, jointly owned liquefaction plant. This model requires the processing of raw gas at each biogas plant, from which the processed biomethane is transported to the liquefaction hub, either as pressurized road transport or in a possible pipeline network. Liquefied biomethane is well suited as a fuel for heavy transport, industry and short sea shipping. An LBG filling station can be connected to the plant, and LBG can be transported by tanker to other applications (e.g. industrial use). Figure 53 shows scenario 2, the liquefaction of biomethane in a centralized, jointly owned liquefaction plant.

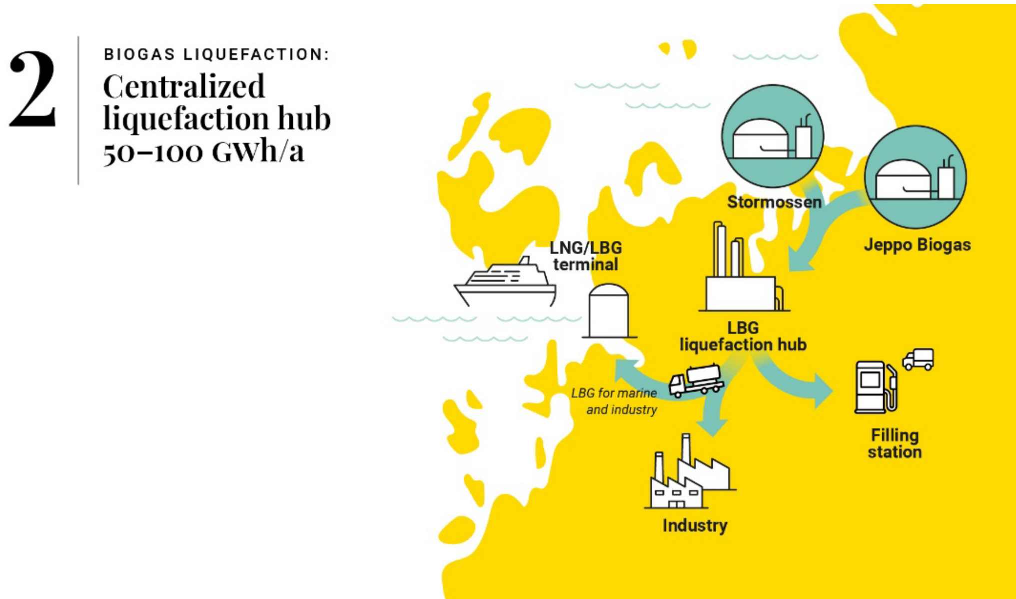

Figure 53. Scenario 2. Biogas liquefaction: Centralized liquefaction hub 50-100 GWh/a

As a summary for scenario 2 it can be stated that there is a need to increase regional biogas production and availability. Both a big 300 GWh or one or more 50 GWh sized plants were considered possible. The process should be started as soon as possible and could be finalized in 2027. Cost calculations in the beginning are very important (investment costs). The question who would be the initiating actor(s) was answered by suggesting to form a regional group to make the initial feasibility study and prepare a limited company or corporation. Dialogue and collaboration between actors from the public and private sector is extremely important in the beginning of the planning. Also, sector coupling (employing hydrogen) within municipal and regional infrastructure planning presents new synergies. Initially named actors to form the group: Vaasa city, Korsholm, VASEK, Merinova and Stormossen.

Scenario 3 (SC3). Regional gas pipeline network

Based on a separate gas pipeline study completed within this project during the summer of 2021 (Välimäki 2021), the third scenario of the workshop was formed: A regional gas pipeline network. The 60 km pipeline route would start at the Jepua Biogas Plant and end at the Stormossen Biogas Plant. In the model, the biogas liquefaction plant is located close to end users in the vicinity of Vaasa. The biomethane network could also be introduced for the development of hydrogen infrastructure in the future.

The 60 km gas pipeline with a transfer pressure of 8 bar would cross Uusikaarlepyy and Korsholm. The profitability limit was compared to CBG transports of 100 GWh/a. The investment cost was calculated to be 8 million EUR. The timeline and steps agreed upon by the workshop group is illustrated in Figure 54.

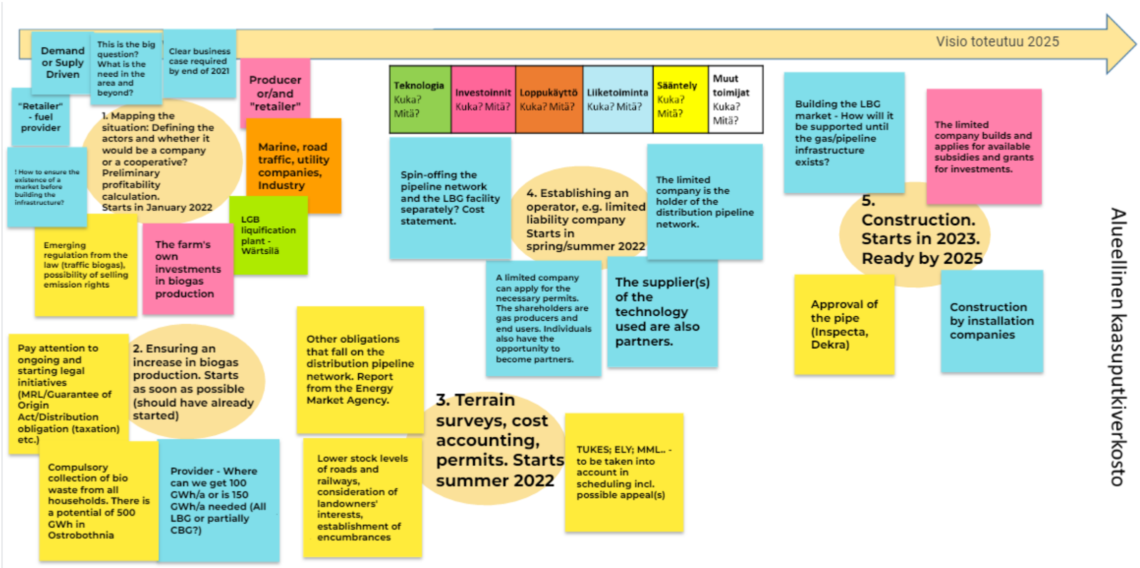

Figure 54. Scenario 3's Jamboard (translated from the original Finnish version)

Results from the workshop (WS2 SC3) discussions:

In the workshop discussion, the timetable was considered far too loose, so it was completely redone: the realization of the vision was rescheduled from 2028 to 2025 and all steps were brought forward.

The workshop discussed whether there should be two actors: one for the pipeline network and one for the equipment. The physical implementation was seen as challenging as the pipeline would go through the estates of many landowners and delays can be expected. The early stage of the value chain was seen as very important: how to collect raw materials? “If a carrot doesn't work, then a stick?”. The starting points for the business economy were seen as important - and it was considered how to ensure the functioning of the market. Licensing plays a key role. In addition, the workshop discussed how to build the LBG market. When gas is started to be produced, it must be used somewhere immediately.

> *"I'm still thinking about establishing a possible joint-stock company and so on. Depending, of course, on how it is decided to divide the costs, e.g. in terms of permits and research, and who will pay them, but at a fairly early stage the matter could be mapped out and it could be said that some sort of letter of intent will be*

> *drawn up with those who are willing to get down to business. At this stage, it can be uncertain whether the founding of the company will take place before or after. But mainly that it is good to have some kind of legal structure already before the stage when costs start to accumulate". (Participant 1 in WS2 SC3)*
>
> *"What is even more important is the investments of these local players, which are outside of this (pipe). They also have to be covered somehow. And everything is probably covered by that LBG price. And considering all these costs, in which different price scenarios is this financially viable? My own view is that biogas is a very viable option, but if it becomes too expensive, and synthetic gas is then cheaper, then this will fall away. Repayment is certainly of interest to all these small players who play a central role in this: when will they get their money back from this investment" (Participant 2 in WS2 SC3)*
>
> *"In this COVID stimulus money, in the sustainable growth program, several millions have been set aside for the expansion of gas networks. So it's good to note: maybe it will change some of these financial calculations in this project as well. But also, if they can be combined with hydrogen projects, there can be synergies that can be significant". (Participant 3 in WS2 SC3)*

Municipalities and local development companies (VASEK, Merinova, Dynamo) as well as ÖSP and Proagria were named as the key actors in moving the plans forward.

Table 30. Key actors in Scenario 3.

Scenario 3	
Level	**Actors**
Macro	The cities through which the pipeline would go, other grantors (state), legislators (Land Use and Building Act + distribution obligation), a limited company if one is established, waste boards. Would it make sense for 2 actors: one for the pipeline network and then one for the plant itself? Synergy with transport projects in the city of Vaasa, statement of obligations from the Energy Market Authority, pipe approval (Inspecta, Dekra), Tukes, ELY, National Land Survey, issuers of Corona Revitalization Fund (Sustainable Growth Program). Farms.
Meso	
Primary actors	Gasgrid, Stormossen, Jeppo biogas, Fingrid, smaller producers along the pipeline if there are pumping stations, the farm's own investments in biogas production
Secondary actors	Other hydrogen projects (synergies with them), Landowners on whose land the pipes are laid on, technical suppliers (LGB liquefaction plant - Wärtsilä?), installers.
Tertiary actors	-
Micro	Urban public transport (if eg biogas buses), marine, road traffic, utility companies, Industry, companies with biogas waste trucks.

Scenario 3, a regional gas pipeline network, is illustrated in Fgure 55.

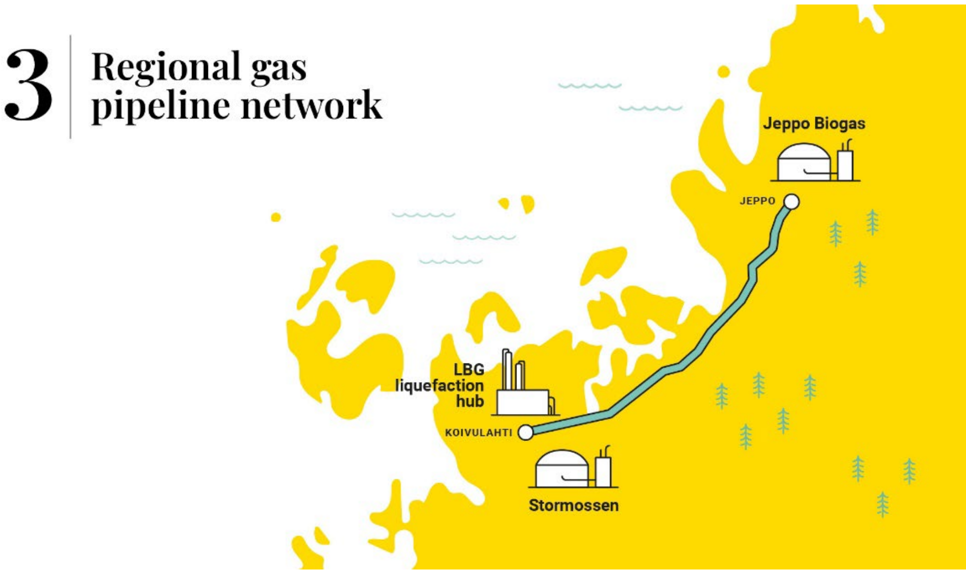

Figure 55. Scenario 3. Regional gas pipeline network.

The 60 km pipeline route would leave the Jepua Biogas Plant and end at the Stormossen Biogas Plant. To sum up scenario 3, it should be started immediately and ready by 2025. It would probably require two different actors, one for the pipeline and another for the machinery. The permissions need time and might be challenged as there are many landowners who would have the pipe crossing their land. One question was how to make the negotiations smooth? Also, the upstream becomes extremely important, how to get enough biomass and raw materials? The business case was also discussed, the question was how to ensure there is a market for the gas? It would be important to collaborate with the hydrogen sector as well as recognize opportunites presented by sectorcoupling. It was suggested to form a regional group with the municipalities and local developing companies (VASEK, Merinova, Dynamo jne) as well as ÖSP ja Proagria who would make the initial feasibility study and prepare a limited company or corporation. The so-called “Mankala principle” could work. The Mankala principle is a method of operation in which several companies establish a non-profit limited company for the common purpose. The model is used especially in the energy sector.

Summary of the scenario work in workshop 2

Figure 56 shows the complete map of the proposed biogas solution scenarios in Ostrobothnia.

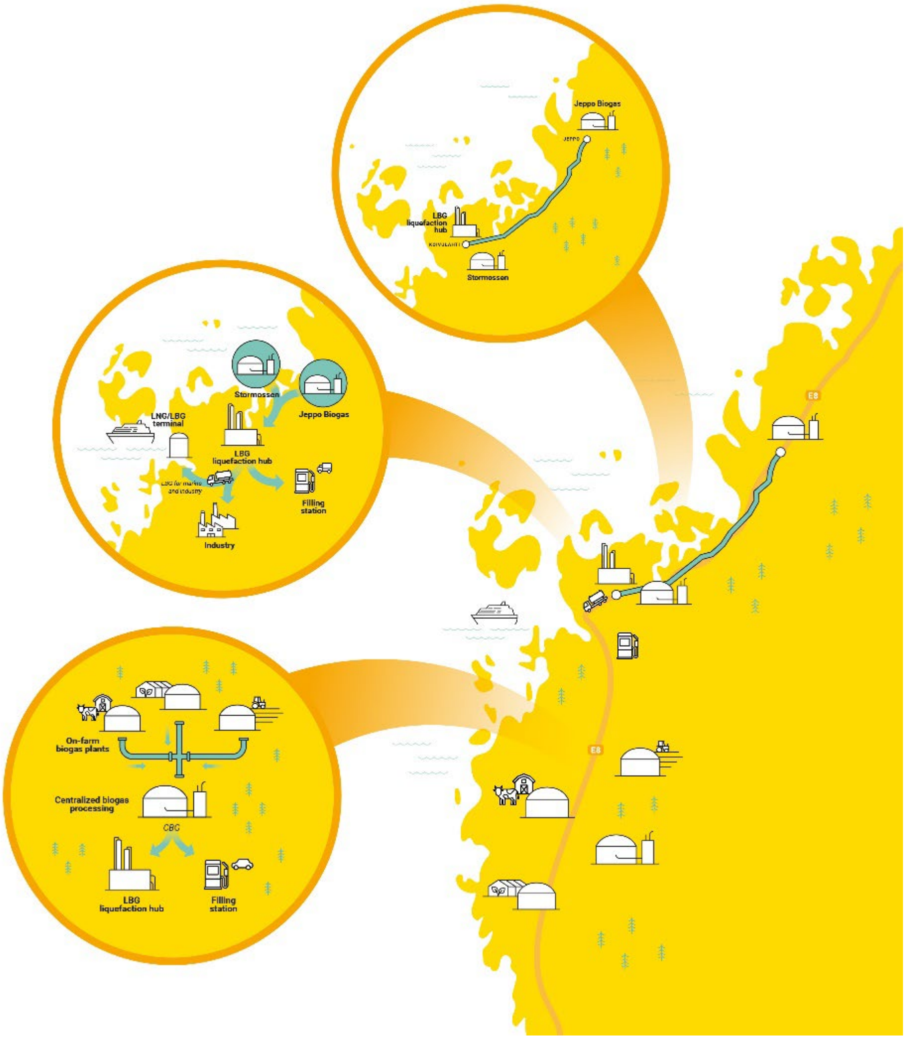

Figure 56. Map of the proposed biogas solution scenarios in Ostrobothnia.

In general, results from the three scenario groups presented an overlap of key actors that were considered central for the furthering of the proposed biogas solutions. Participants also agreed with the above pictured map, where the scenario 1, small scale biogas plants and local pipeline was situated south, towards the municipalities of Närpes, Kristinestad and Kaskö where there are plenty of greenhouses, farms and fishing industry. The LBG hub was placed in the Vaasa – Korsholm area, close to the energy and circular economy clusters as well as the existing Stormossen biogas plant and Westenergy. As Jeppo and its surrounding municipalities, situated northwards, have their own biogas plant and network of feedstock providers (farms and industry) the pipeline was suggested to be built between the two major biogas areas, Vaasa – Korsholm and Jeppo. Table 31 summarizes key actors in the Ostrobothnia biogas sector. Actors are divided into macro, meso and micro level according to societal roles, e.g. governance, business and individual users.

Table 31. Actors of scenarios 1, 2 and 3.

Level	
Makro	
Regional Council of Ostrobothnia	Issuers of Corona Revitalization Fund (Sustainable Growth Program). Other grantors (state)
ÖSP	Legislators (Land Use and Building Act + distribution obligation)
ÖSL	A limited company if one is established
ProAgria	Waste boards
EU Life funding targets	Would it make sense for 2 actors: one for the pipeline network and then one for the plant itself?
MTK	Synergy with transport projects in the city of Vaasa
Advocacy companies	Statement of obligations from the Energy Market Authority
Finland	Pipe approval (Inspecta, Dekra)
TEM	Tukes
Business Finland	ELY
Ostrobothnian development companies (Konkordia, Vasek, Närpes Dynamo ja Kristiinankaupungin Elinkeinokeskus) + the cities through which the pipeline would go	National Land Survey
Municipals Vaasa, Kristiinankaupunki, Närpiö	
Meso	
Primary actors	
Jeppo Biogas	Representative of Närpiö greenhouse farms
Stormossen	Equipment suppliers: Sarlin, Sterling Cryogen, CryoPur, Air Liquide, Wärtsilä, Wega
The company / cooperative running the rotating unit	Operators already have a production plant up and running
Gasum	Biogas consortium?
Gasgrid	Fingrid
Farms (farms' own investments in biogas production)	Smaller producers along the pipeline if there are pumping stations
Secondary actor	
Consultant company	Other hydrogen projects (synergies with them)
Valio	Landowners on whose land the pipes are laid on
ST1	Technical suppliers (LGB liquification plant - Wärtsilä?), installers
Tertiary actors	
Universities	University of Applied Sciences
Mikro	
Urban public transport (e.g. biogas buses)	Marine, road traffic, utility companies, industry
Companies with biogas waste trucks	

5.2.3 Workshop 3 “Carbon-neutral waste transport - Improving collection and the role of biogas and the opportunities for cooperation in Ostrobothnia”

The third workshop “Carbon-neutral waste transport - Improving collection and the role of biogas and the opportunities for cooperation in Ostrobothnia” was held on Zoom 30.11.2021. The aim of the workshop was to bring together waste management actors from different parts of Ostrobothnia to discuss how biowaste collection could be made more efficient. In addition, the role of biogas in contributing to the carbon neutrality of waste transport was discussed. The workshop had 12 participants from Stormossen, Biokierto, Jeppo Biogas, Pohjanmaan jätelautakunta, Vaasan kaupunki/Jätelautakunta, Vaasan kaupungin ympäristöosasto, Lassila & Tikanoja, Stormossen, Westenergy, Vestia, and Remeo.

The workshop was held against the backdrop of the ongoing change in the Finnish waste legislation. According to Finland's National Energy and Climate Action Plan, greenhouse gas emissions from domestic transport must be reduced by 50 per cent by 2030 (reference level 2005). In 2030, the calculated share of transport biofuels in the total fuel used would be 30%. Also, the Medium-term Climate Plan (Keskipitkän aikavälin ilmastopolitiikan suunnitelma, KAISU, Ympäristöministeriö 2022) aims to promote the use of biogas in work machines by 2030. Central to this is the efficient use of materials and by-products from industry and agriculture and the implementation of resource-wise practices. In the following section, the background information that was used to further discussions is presented.

Improving the collection of bio-waste

The obligation to collect bio-waste - New Waste Act 19 July 2021 states that: “According to the revised Waste Directive, 55% of municipal waste must be recycled in 2025 and 65% in 2035. Municipal waste includes household waste and waste from production comparable to household waste. The current recycling rate is around 42%, so sorting and separate collection of waste from properties needs to be significantly increased.” The obligation to collect biowaste for all properties will be realized 3 years after the law enters into force. (Finncont 2021).

For decades, Finland has had the so-called dual system, i.e. the municipality, has been able to decide whether to tender for the organization of waste management itself or to allow housing companies and residents to tender. The new Waste Act proposes the abolition of the current dual system for the transport of separately collected waste, which is the responsibility of the municipality, and the transition to municipal waste transport. In the past, a resident or housing association could have arranged the waste transportation themselves. (Mäkilä 2021).

The role of biogas in promoting carbon neutrality in waste transport

The use of biogas in transport reduces greenhouse gas emissions during the fuel life cycle by 85-90%. The greenhouse gas savings from biogas use are based on the fact that the biogenic carbon dioxide released during the combustion of biomethane is part of the natural carbon cycle. Replacing fossil fuels with renewable biomethane will not increase the net amount of carbon dioxide in the atmosphere, because equally much carbon dioxide is released during combustion as has previously been bound by the biodegradable material from the atmosphere. The public sector can lead the way in reducing emissions. In the procurement of transport, this is reflected in the effort to decrease the use of fossil fuels.

There are already some Finnish waste enterprises who use biogas in their vehicles, in the following are two examples: In its tender issued at the end of 2019, Jätehuolto in Southwest Finland (a municipal enterprise owned by 17 municipalities in Southwest Finland) applied for more environmentally friendly and low-emission vehicles for its waste transportation contracts. The condition for the tenders for Raisio's and Naantali's combustible waste transport contracts was that the waste transports be handled by waste trucks using biogas as fuel from 2020. (LSJH 2020). Pirkanmaan Jätehuolto (this is also a municipally owned company) currently has 11 gas-powered waste trucks. Upgrading all 40 waste trucks to gas would reduce emissions from waste transport by about 1,900 tonnes of CO_2 per year.

A gas truck is well suited for waste collection if the filling station is along or near its operating route. Figure 57 shows the location of biogas filling stations by province in Finland.

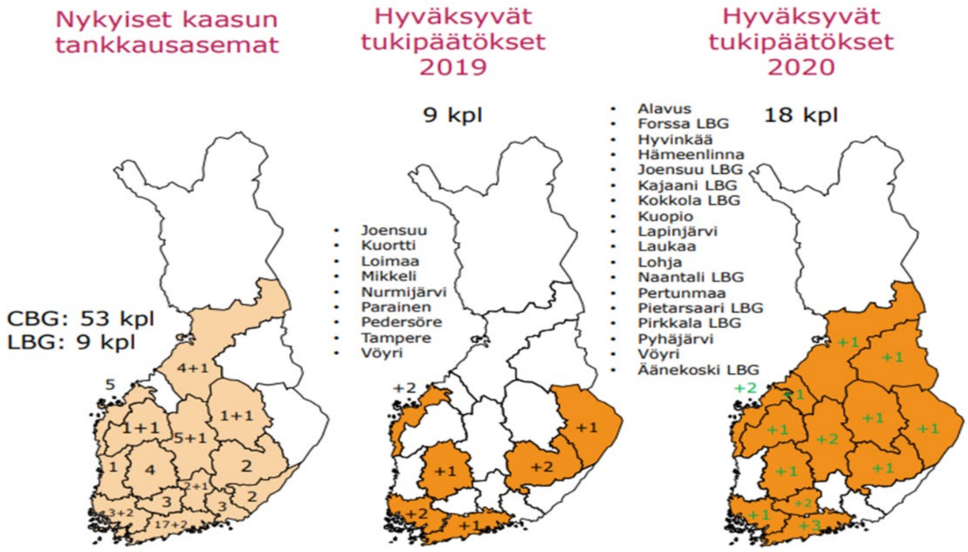

Figure 57. Current gas filling stations, approved subsidy decisions 2019, approved subsidy decisions 2020 (from left to right) (Energiavirasto 2021).

Within the present project, a study has been carried out on the durability and usability of gas-powered vehicles titled “Study on the durability of heavy vehicles and the need for maintenance in biogas use” (Välimäki 2021). The study utilized maintenance information provided by operators of biogas plants. The maintenance history of the equipment was used to analyze the maintenance intervals of the various components of the equipment and the component failures encountered by them.

No problems associated with spent fuel were identified in the vehicle maintenance history, and no abnormalities were found in vehicle service intervals. The study also collected user experiences of professional drivers using biogas vehicles. The user experience collected showed that the biogas-powered fleet was at the level of conventional diesel-powered vehicles.

Findings from the 3rd workshop

The first part of the workshop was used to discuss how biowaste collection could be made more efficient. The idea was to enable different actors to express their views and by doing so, extend the system level understanding of what would be needed to bring forth changes and what kinds of collaboration would be needed.

> *"The Waste Board's decision on how extensive, for example, this bio-waste collection will now be extended, is absolutely crucial. Because if they don't require it in sparsely populated areas, it won't be collected. From what we have studied there, there is not necessarily a great enthusiasm for that kind of sorting. We offered a hundred customers the opportunity to try sorting with a biowaste container and we offered them free transport. Out of 100 customers, three*

continued to use the service. At this point, I would see that it is almost a requirement that it comes through an order. Unfortunately, I don't believe in voluntary participation in that." (Participant 1 in WS3)

"The fact that we do regionally good things within the province, or even in the region of three or four provinces, is not necessarily enough. The infrastructure should be comprehensive. And this is, of course, a bit of a challenge when you have looked at those EU-level requirements about what kind of infrastructure needs to be built. There, electricity and hydrogen are the investments that are very much required. Perhaps nationally, things should also be done to ensure that this network has sufficient conditions everywhere. Otherwise, maybe at least LNG will not take off in the same way in this business fuel distribution". (Participant 2 in WS3)

Table 32 presents different level actors and what would be needed to make biowaste collection more efficient.

Table 32. More efficient biowaste collection: actors and requirements

Actor	What is required for change?	Collaboration
Companies	More & new raw materials would enable new investments	All actors: Need for open dialogue with other actors of value chains
	Ensuring the profitability of the biogas plant	Waste boards, municipalities & citizens
	Higher calorific value of the waste	Housing companies and real estate companies
	Better material circulation in the operating area	Municipal waste treatment plants
	Impact assessment: How does the increase in separate collections affect the number and types of vehicles?	Waste treatment plants
	Biowaste producer - municipal citizen? "Prosumer"?	Waste management companies
	Increased collections. More route efficiency and work for the locality.	Companies producing bio-waste (not included in the collection organized by the municipality)
Social companies	Guidance and counseling for customers are increasing	In a sparsely populated area, requires local commitment – Residents of municipalities
	Potentially increasing shipments of biowaste	Sewage treatment plants
	More biowaste for processing - Increasing the processing capacity	Users of recycled nutrients and fertilizers (agriculture, food industry)
	Changes to logistics	Authorities, customers
Public sector	Increasing control (separate collection of biowaste)	Residents of municipalities + other stakeholders
	Guidance and counseling are increasing	Transport contractors
	Expansion of the current operation in the area. The current system will be expanded in accordance with the requirements of the law	With the authority, residents and companies in such a way that the service is implemented easily and efficiently from the users' point of view and they receive sufficient guidance and advice.
	Waste management regulations will be strengthened. Goal: the new waste management regulations will enter into force in 2022.	Customers and waste handlers (municipal and private handlers)
Customers	New traffic gas customers for the stations?	
	Residents of the municipality as prosumers	

The second part of the workshop was used to discuss the role of biogas in contributing to the carbon neutrality of waste transport. As in the first part, the aim was to facilitate discussion and expression of opinions that would create more system level understanding of the needs and actions in the field.

"Biogas is a great practical example of a circular economy. Based on our collection data, we calculated that a biogas-powered car, when collecting biowaste, gets five times more biogas from the biowaste it collects during the route than the car has consumed during the route. It's a great example that it produces". (Participant 3 in WS3)

"'Carbon neutrality should be the goal.' - this is already a good sentence. Waste transport should be part of the path to carbon neutrality, and biogas is one partial solution in that path. So, this should be the goal. And this life cycle thinking, and value chain thinking is also necessary here. If carbon neutrality is the goal, then the role of biogas is recognized here, whether it is waste transport or something else. Then it is a permission and an opportunity for a biogas plant to invest. And at the same time, it's also a signal for waste drivers to start investing in a certain type of equipment. They need signals, and they need political decision-making." (Participant 4 in WS3)

Table 33 presents different level actors and what would be needed to use biogas in waste transports.

Table 33. Use of biogas in waste transports: necessary actors and actions.

Significance for the company's operations	Collaboration
A company's carbon neutrality goal	Stakeholders of the own survey project and other biogas projects in the area. Transport contractors.
Climate goals of the city & municipality	
Biogas plant investments - more production and distribution	
Waste transfer loading	Transport companies, other gas station operators
New traffic gas customers	
Gas production to be increased. New stations for central traffic areas?	
Upgrading of fueling stations to suit heavy lorries	
Predictable fuel price development	Biogas distributors
Refueling possibilities, emission targets, fleet availability and alternatives.	Customer organization, chassis manufacturers, superstructure manufacturers. Collection equipment suppliers. Also with customers in the trade and industry segment.
Regulations->More material for digestion, but composting will also be allowed in the future	Advocacy cooperation in relevant directions. The Finnish Transport and Logistics SKAL/ Suomen kierovoima KIVO confrontation in the Waste Act does not promote upper-level goals
Less emissions from the waste sector ==> carbon neutrality	
Tendering for waste transport & price promise to drivers	Municipality, public sector, waste board

Altogether, the waste sector in Ostrobothnia is undergoing a transformation towards a more “top down” system where municipalities have more power and responsibility. This situation challenges many small waste transport enterprises as they need to update their vehicles as well as contracts. There are challenges and opportunities in “smartening” the waste sector in Ostrobothnia. Clearly, it requires the waste boards, waste transport companies, municipal actors together with the waste management companies to maintain an open dialogue. Also, biogas (or LBG) as a renewable fuel presents a promising option for the collectors and other operators in the sector. Table 34 summarizes the main waste sector actors and activities in Ostrobothnia.

Table 34. Actors of carbon-neutral waste transportation

	Carbon-neutral waste transportation
Level	**Actors**
Makro	
	Supervising authority
	Waste Board
	Municipalities (including Vaasa)
	Gasum
	Suomen kiertovoima KIVO
	EU legislators
	Suomen kiertovoima's campaigns
	Advocacy cooperation in relevant directions. The Finnish Transport and Logistics SKAL/ Suomen kierovoima KIVO confrontation of the Waste Act does not promote top-level goals
Meso	
Primary actor	Waste companies
	Vestia
	Transport companies
	Local wholesale water company (sewage sludge)? Sewage treatment plants
	Stormossen
	Farmers
	Westenergy
	Jeppo Biogas
	Waste producers (a citizen or a company)
	Companies producing bio-waste (not included in the collection organized by the municipality)
	Municipal waste treatment facilities
	Municipal and private waste handlers
	Other biogas suppliers
	Biogas distributors
Secondary actor	Chassis manufacturers, bodywork manufacturers, collection equipment manufacturers
	Wärtsilä
	Environmental management experts?
	Will we have foreign players here for our biogas sector, distributors, or perhaps producers, or investors?
Tertiary actors	Other biogas projects in the area?
	Universities
Mikro	

	Households, residents (paying for the service)
	Companies (paying for the service)
	Trade-. industry and tourism
	Gas users, heat users, users of recycled products
	Recycling of nutrient and fertilizer users (agriculture, food industry)

5.3 Common Operating Models

By generating new information on the issues covered during the three workshops and bringing together key regional actors to consider workable ways to bring about the desired change, important conditions can be created for increasing the use of biogas and the biogas business in Ostrobothnia. This requires an in-depth understanding of end-user needs (under which conditions biogas could play a greater role in different companies and how this development could be supported), techno-economic realities (e.g. to build liquefied biogas infrastructure) and the potential of different actors to contribute to.

The work undertaken in the work package 4 could loosely be described as building a transition agenda (see Loorbach 2010), as we have been working with transition visions (the scenarios), building coalitions (dialogue mechanisms) and tied the discussions to the techno-economic realities presented by research conducted in the other work packages. As a result, we have brought together actors from various fields of expertise to discuss and give insights into the next steps for furthering the biogas solutions in Ostrobothnia.

It has become clear that biogas, both in its gaseous and liquid form, is considered important in the regional energy mix. Figure 58 presents the “Ostrobothnia biogas playing field” where the inner circle includes the most central actors, the middle important partners, feedstock and knowledge providers and the outer circle the end users as well as the state.

Figure 58. Ostrobothnia Biogas Playing Field

The inner circle of the playing field includes both private and public partners, actors who need to communicate and collaborate when new biogas plants, filling stations or (pipe) infrastructure are planned. The middle circle includes important stakeholders who need to be included to ensure feedstock availability, users, transport as well as R&D. The tertiary actors in the outer circle are end users as well as the state, important for the future development of biogas solutions but not in direct collaboration with regional actors.

Finally, a “big picture” or common operating model for biogas solutions was developed. This model combines the findings from the three workshops to envision the main steps and groups of actors needed to take the plans further. The model consists of three main steps, where the first 1. Regional group public & private stands for a collaboration between key actors to initiate the process. This group has the power to take the initiative and gain enough support as well as expertise to start the process. The second step, 2. Mapping & calculation, includes various actors who deal with the permissions, legislation, feedstock availability and cost calculations and obviously technical solutions. Thirdly, 3. Business model, concretizes the “how” to operate the proposed biogas solution. Figure 59 shows the steps and suggested actors for each.

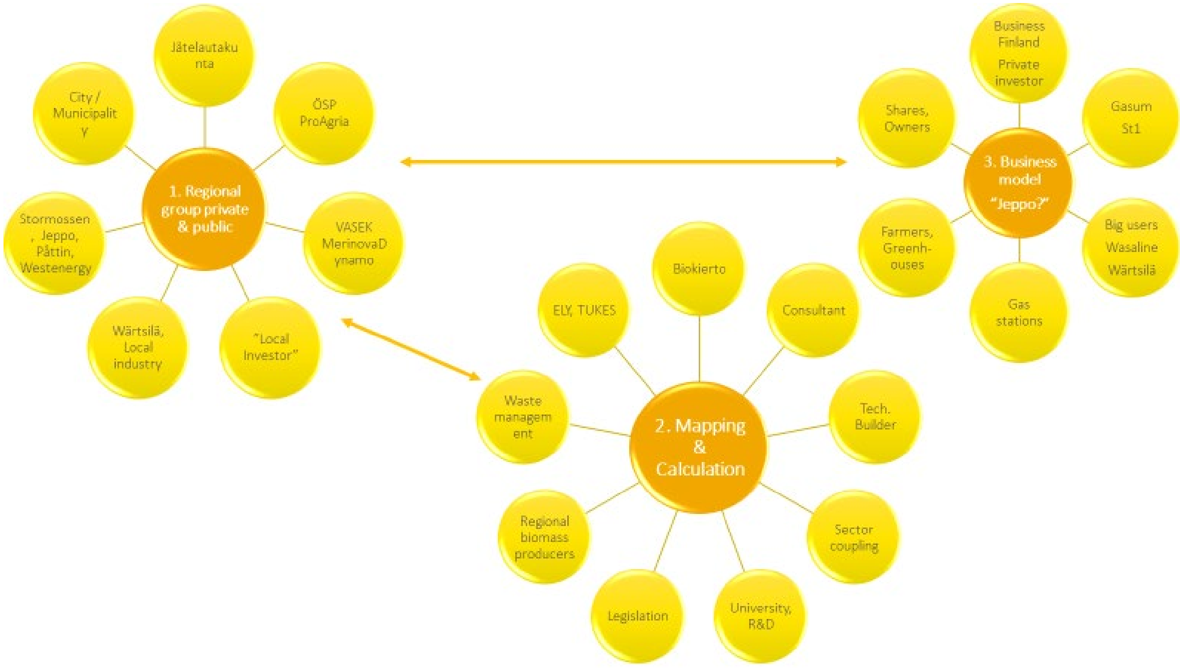

Figure 59. Common operating model for biogas solutions in Ostrobothnia

The common operating model for Ostrobothnia shows that an increased collaboration between existing biogas actors, local industry, municipalities, local developers as well as investors could be beneficial. This would enable a strong coalition and help avoid unnecessary challenges in the next phases. The core group would include a large network and expertise, and "know the process from before". When the plan is in its first stage, the second group includes the different actors needed to materialize the vision. And simultaneously, the third step involves the parties who can support the economic realization.

In general, there is a big interest in leveling up the biogas production and distribution in Ostrobothnia. There is an increasing interest from both big, industrial players and smaller businesses, as well as private users (cars) to use biogas.

5.4 Summary and conclusions

There is political and environmental pressure for the renewable energy source market and the biogas market to grow in the EU, Finland and Ostrobothnia. The sector is expected to grow with an increasing focus on LBG. Biogas solutions provide many opportunities of which the main ones include the use of feedstock from farms and agriculture, usage of gas in transportation and processing of digestate. Issues to be considered from a sustainability perspective are the choice of biomass (e.g., challenges in using feedstock from forest biomass, high Indirect Land Use Change (ILUC) or municipal waste if it includes a lot of pollutants), localization of the units to avoid transport and connection costs as well as the size of the plant. Also controlling the possible methane leakages of plants and vehicles is crucial and requires a skilled workforce. Altogether, the future direction of biogas solutions in Ostrobothnia, as well as Finland, is still unclear due to legislative issues, investment costs, lack of knowledge and collaboration between key actors. Should the biogas industry receive sufficient support the industry can be expected to grow considerably and within different business areas.

Until the beginning of 2022, a gradual increase in supply and demand has been considered as the most likely trajectory for biogas solutions, as a rapid spread in market terms alone seemed unlikely. The price competition with natural gas and other fossil fuels made investment decisions risky on both the producer and user side. Since March 2022, the geopolitical situation (Ukraine crisis) combined with the ambitious climate goals, seems to be changing the situation at EU and national level, and the role of biogas in the green transition as well as energy security is being reconsidered. Still, the current energy directives lack support for biogas solutions, even if biogas is considered to play an important role as energy source, boosting the circular economy through nutrient recycling and supporting agriculture as well as compatible with the rollout of hydrogen.

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6 CONCLUSIONS

The purpose of this project was to support the transition of Ostrobothnian actors to a low-carbon and resource-efficient society in context of the biogas business. Its overall goal was to build new knowledge and create favorable conditions for biogas business and biogas use to grow through feasibility studies, measurements and common operation models. The main findings were:

- Increasing biogas use would be a quick and cost-effective way to reduce GHG emissions from urban traffic. Well-to-wheels analysis showed that up to 90 % GHG emission benefit could be achieved by switching from diesel to biomethane, giving a strong environmental argument for biogas use.

- Biogas could offer a viable alternative also for industrial operators and the energy sector to meet their emission targets. In addition, with rising fossil fuel prices, renewable energy sources are expected to become increasingly competitive with fossil fuels.

- To make biogas a realistic option for potential new end-users – such as industry, heavy traffic, and marine sector – the production and supply of liquefied biomethane, in particular, needs to be increased.

- The Finnish greenhouse industry uses already renewable energy in half of the heat energy consumption. Employing CHP with biogas could enable covering part of the electricity use too.

- The plant waste from greenhouse industry alone will not be enough to considerably boost biogas production in the region. Nevertheless, the waste material has the potential for biomethane production.

- Capturing carbon dioxide from biogas production facilities is possible and under development.

- Investments in local small-scale biogas liquefaction and/or a regional biogas pipeline could be the next major step in promoting biogas use in Ostrobothnia.

- The common operating model for Ostrobothnia shows that an increased collaboration between existing biogas actors, local industry, municipalities, local developers as well as investors could be beneficial. This would enable a strong coalition and help avoid unnecessary challenges in the next phases.

- There is a big interest in leveling up the biogas production and distribution in Ostrobothnia. There is an increasing interest from both big, industrial players and smaller businesses, as well as private users (cars) to use biogas. However, the future direction of biogas solutions in Ostrobothnia is still unclear due to legislative issues, investment costs, and lack of knowledge. With sufficient support, the biogas sector can be expected to grow considerably

Appendices

Appendix 1. Project poster presented at The Research Exhibition of Energy at the Vaasa EnergyWeek 2022.

Biogas Utilization Opportunities in Ostrobothnia Region

Aim

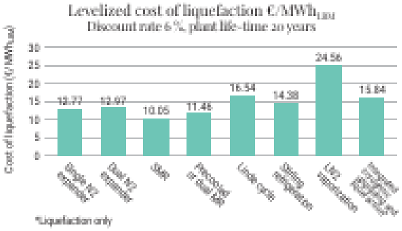
The project's overall goal is to build new knowledge and create favorable conditions for biogas business and biogas use in the Ostrobothnia region through feasibility studies, measurements, and common operation models.

WP1

WP1: Biogas infrastructure development options in Ostrobothnia

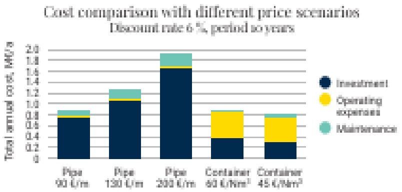
Techno-economic analysis of biomethane liquefaction processes

- technical descriptions of liquefaction processes suitable for small-scale production and an overview of commercially available solutions for each technology
- life-cycle cost analysis



Gas pipeline to Ostrobothnia – feasibility and cost assessment

A proposal for the gas pipeline route and a comparison of the investment and operating costs for pipeline transmission versus CBG transportation.

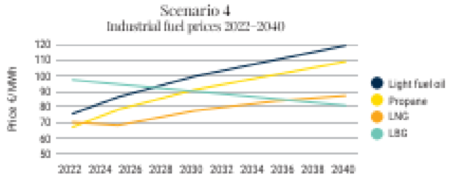


- pipeline cost may be competitive to CBG transportation in easy installation environments and with higher transmission volumes
- despite the potentially higher costs, pipeline investment may be supported by transmission reliability, long service life, and low and stable operating costs
- **In the future, the Ostrobothnian gas pipeline could be part of the hydrogen energy transition**

WP3

WP3: Biogas utilization opportunities in different contexts: industry, waste-to-energy sector, and greenhouses

Integrating biomethane into industrial energy systems requires a predictable operating environment. WP3 focused, e.g., on the prospects of biogas availability, especially LBG, and on industrial fuel price forecasts.



With rising fossil fuel prices and taxation, renewable energy sources are expected to become increasingly competitive with fossil fuels.

WP4

WP4: Common operating models

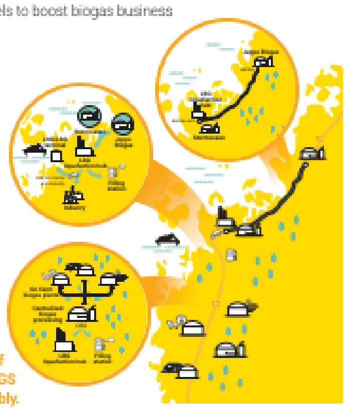
Current state analysis 2021 of the state of the EU, Finnish and Ostrobothnia biogas sector through literature and interview findings.

3 Workshops with participants from BGS sector and outside to

- create new connections and networks between different actors in the region
- develop common collaboration models to boost biogas business

Current state Ostrobothnia
3 biogas producers
4 gas filling stations
Opportunities for BGS Markets:
sustainability & legislation
Raw-materials: agricultural sector
Producers: know-how
Logistics: biogas vehicles, building gas pipe
Users: maritime, agriculture, transport
General: growing interest in BGS development

Future direction of biogas solutions in Ostrobothnia still unclear due to legislative issues, investment costs and lack of knowledge. With sufficient support the BGS sector can be expected to grow considerably.



Central findings regarding cooperation models for sustainable utilization of biogas, need to:

1. Active communication & collaboration between public and private sectors
2. Form a multi-stakeholder group with local actors (City of Vaasa & other municipalities, VASEK, Merinova, Dynamo, ÖSP & ProAgria) to start the planning process
3. Use the Jeppo corporative model
4. Combine with sector coupling & hydrogen
5. Collaborate with municipal infrastructure planning
6. Need to act now!

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