



Explorative economic analysis of a novel biogas upgrading technology using carbon mineralization. A case study for Spain



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ABSTRACT

This paper studies the potential application of a novel biogas upgrading technology called alkaline with regeneration (AwR). This technology uses an alkaline solution, along with carbon mineralization, to remove and store CO₂ from biogas in order to create biomethane, a substitute of natural gas. Three different applications of biogas were explored for their potential economic benefits along three different biogas generation capabilities of landfills in Spain (250 Nm³/h, 1000 Nm³/h and 5000 Nm³/h). The scenarios include upgrading biogas using AwR and injecting the biomethane into the natural gas grid, or selling the gas as a vehicle fuel. The third reference scenario assessed directly burning the biogas for the production of electricity. The latter showed an annual profit of 0.2–5 million €₂₀₁₂ while upgrading the biogas to obtain biomethane showed an annual loss of 3–50 million €₂₀₁₂. This was due to the operational costs involved in AwR, namely the cost of NaOH (principal reagent) and the treatment of wastewater. Increasing revenue can help obtain an annual profit. In order to break-even it would be necessary to raise CO₂ credits to 99 €₂₀₁₂/t or, through feed in tariffs, increase the price of the sale of biomethane to 0.25 €₂₀₁₂/kWh.

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1. Introduction

It is predicted that in the year 2020 Europe will produce 10 billion m³ of biomethane solely from the biogas of landfills [1]. While this biogas can be considered as an environmental contaminant due to its high concentrations of methane (CH₄) (35–65%) and carbon dioxide (CO₂) (15–50%) [2,3], for the same reasons it can be considered as a potential source of energy. CH₄ is a powerful greenhouse gas (GHG) that is 34 times more potent than CO₂ in trapping heat in our atmosphere [4] and therefore concerns have been raised in minimizing such emissions [5,6]. Furthermore, as it has a high calorific value it is also a potential source of energy.

By removing the CO₂ from biogas through the application of carbon capture technologies, it is possible to obtain a high concentration of methane, often referred to as biomethane, which is comparable to commercial natural gas. This allows for biogas to become a potential source of alternative natural gas, and can therefore have the same uses as natural gas. In this paper attention is focused on two of those uses, as a fuel for vehicles or it could be fed into the natural gas grid.

The application of carbon capture to biogas in order to form biomethane is called biogas upgrading. While it utilizes carbon capture technology it does so at a smaller scale than what is currently envisioned when referring to carbon capture (for example power plants). This smaller scale also allows for the deployment of novel capture techniques which have not yet been tested on or proved at a larger scale. One such example is carbon mineralization. This process has been gaining interest as a viable route for carbon storage [7–9] as it uses a chemical reaction to convert the CO₂ into a non-soluble solid compound. Materials that contain metal oxides (such as calcium oxide (CaO) or magnesium oxide (MgO)) are put in contact with CO₂. The metal oxides react with the CO₂ to form a carbonate (calcium carbonate (CaCO₃) or magnesium carbonate

Abbreviations: APC, air pollution control; AwR, alkaline with regeneration; GHG, greenhouse gas.

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(MgCO_3). Metal oxides occur naturally in minerals such as silicate, serpentine and olivine. High levels of CaO can also be found in industrial wastes such as air pollution control (APC) residues from municipal solid waste incinerators [10]. While the composition of APC residues can vary greatly, the residues are mainly made up of fly ash, chlorine based salts and inorganics such as heavy metals (which can leach resulting in APC being classified as a hazardous waste) [11]. They also contain calcium hydroxide ($\text{Ca}(\text{OH})_2$) at around 36% (w/w) which is reactive with CO_2 [12]. There has been growing interest in using carbon mineralization for biogas upgrading and one such technique that is being developed is called *alkaline with regeneration* (AwR) [13,14]. This process uses an alkaline solution to strip CO_2 from biogas and then this solution passed through the APC residues in order to store the CO_2 while at the same time regenerate the alkaline solution. This technology, currently at the pilot plant stage, presents an advantage over current biogas upgrading technologies as it stores CO_2 while it captures it.

There are currently six biogas upgrading technologies that are on the market, which include high pressure water scrubbing, chemical scrubbing with amine, pressure swing adsorption, cryogenic separation, membrane separation and organic physical scrubbing. These technologies all help isolate methane by capturing impurities such as CO_2 from the biogas stream. However, currently most captured CO_2 is released back into the atmosphere as the conditions necessary to create a business case are not present (availability of transport infrastructure, market uses of CO_2 at the right location, etc.). Interest has been growing in biogas upgrading technologies and various facilities exist. While biogas upgrading has been applied to certain regions such as Germany and Sweden, their application has however not been very widespread [2,15]. Application of biogas upgrading technologies focuses on facilities that have anaerobic digestion of organic matter, e.g., agricultural facilities that deal with waste crops and manure, and waste treatment facilities such as wastewater treatment, anaerobic digestion of municipal solid waste and landfills for municipal solid waste. The latter of which is the focus of this article. The biogas produced from each source differs in its final composition due to the differences in its input. Meanwhile pre-cleaned non-upgraded biogas can be burned directly for electricity (for example in a gas generator or CHP (combined heat and power)). When it is upgraded the biomethane is an alternative source of natural gas and can therefore be injected into the natural gas grid, or be used as a vehicle fuel, all of which could bring a profit to the owner of the biogas upgrading facility.

The novel technology, AwR, poses an interesting issue in that it can be profitable while capturing and storing CO_2 at the same time. Though as this technology is still at the pilot plant stage it is important to review whether the application of this technology can be economically feasible and where focus should be placed in order to maximize profits. Therefore this article explores the potential application of AwR in three different landfill sizes in Spain, with increasing biogas generation, and explores the potential costs involved in the upgrading and injection into the gas grid, as well as selling it as vehicle fuel.

2. Methodology

This article follows a techno-economic study conducted by Lombardi and Carnevale [16] in which the total cost of a $250 \text{ Nm}^3/\text{h}$ AwR facility, under different working conditions (applying reuse of wastewater, as well as varying base type and concentration) in Italy, was determined [16]. This article looks to apply the AwR technology, which was determined to have the lowest specific cost, in landfills in Spain and examine under which economic conditions

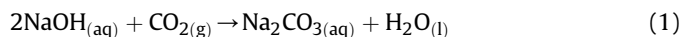
and technological scale a profit can be obtained by selling biomethane for different final applications. As the technology is still in the pilot plant stage, and considering the time needed to upscale to operational level, it is assumed that the upgrading facility will become operational in 2025.

In this section the following will be discussed: the technical details of AwR, the different scenarios under review, and the economic model that was used.

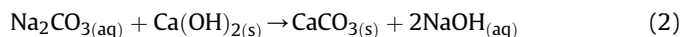
2.1. Technical information

The technology under review is the alkaline with regeneration (AwR) process (Fig. 1). During the development of this technology there were various different combinations of working conditions that could be applied. It was decided to select the working condition that presented the lowest environmental impact for this technology [17], which is AwR using a 10% concentration of NaOH and re-using the wastewater. This working condition was also found to have the lowest annual cost in the study by Lombardi and Carnevale [16].

In this process, water and NaOH are first mixed to form a solution of 10% concentration by mass.¹ This is passed through a packed column in which the biogas is pumped through. The CO_2 absorbs to the NaOH according to equation (1) and the biogas is upgraded. The resulting CH_4 rich gas leaves the system.



The loaded solution is then pumped into a mixer that is filled with APC residues that has been prewashed and filtered to remove the heavy metals and chlorine [16]. The resulting wastewater is sent for treatment and disposal. The sodium carbonate (Na_2CO_3) reacts with the $\text{Ca}(\text{OH})_2$ to form CaCO_3 as seen in equation (2). Meanwhile, the NaOH solution is regenerated at a rate of 61%. The slurry is removed and fresh APC that has been prewashed is placed into the mixer.



The slurry is passed through a filter to separate the regenerated NaOH solution and the carbonated APC residues. The regenerated NaOH solution is pumped back into the column, along with the necessary make-up of water and NaOH (39% make-up solution is required). The carbonated APC residues are then post-washed to remove any excess alkaline solution and this wastewater is sent back into the process as the water to pre-wash the APC residues.² The carbonated APC residues have an improved leaching behaviour and therefore can be disposed of and treated as non-hazardous waste [11].

2.2. Conditions and scenarios

Three cases were selected for potential biogas generation, based on landfill data in Spain [18] and standard sizes of conventional biogas upgrading technologies [2]. The first case is a generic landfill that generates $250 \text{ Nm}^3/\text{h}$ of biogas, which is the size at which the developers of AwR focused their study [16] and can be considered as a mid-range biogas collection rate. The second case is a generic landfill that generates $1000 \text{ Nm}^3/\text{h}$ which is found generally in

¹ Other variants of the process, not examined in this study, include using KOH instead of NaOH and using NaOH at 13% concentration.

² A variant of the process, not examined in this study, includes sending the wastewater generated from the post-washing directly to be treated at a wastewater treatment facility, as opposed to reusing it for the pre-washing.

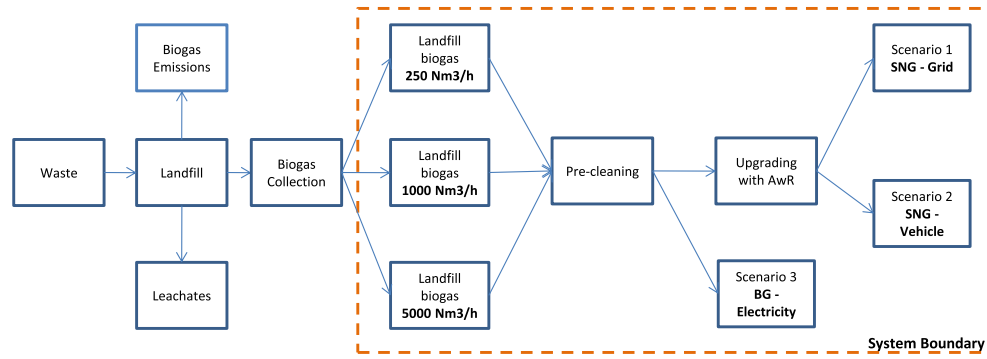


Fig. 2. Schematic overview of investigated systems.

the operation and maintenance costs were assessed. Thirdly, the different scenarios were examined.

The equipment costs and operational flow rates of the AwR were provided by the developers [16,26]. As it was necessary to resize the capacity of the technology from 250 Nm³/h to 1000 Nm³/h and 5000 Nm³/h, a factored estimation method was used and a scaling factor was applied to each individual component using equation (3) [27,28]. Table 2 shows a breakdown of the components and the scaling factors that were applied, which include the column, pumps, stir tank, filters and other components. The building in which the upgrading facility is housed was assumed to be 16% of the total capital cost. The balance of the plant was included at 15% of the total cost of the plant [29]. Financing, permitting, and start-up was not included.

$$z_s = z_0 * \left(\frac{x_s}{x_0} \right)^{SF} \quad (3)$$

where, z_s = scaled cost, z_0 = initial cost, x_s = actual scale, x_0 = initial scale and SF = scaling factor.

Once the total capital for each biogas upgrading capacity was determined, the annual capital cost was calculated using equation

(4) using the discount rate and lifetime defined in Table 3. The same equation was applied to all other infrastructures used in the study, for example the pre-cleaning equipment, vehicle fuelling station, gas generator, etc.

$$A = I * \frac{r}{(1 - (1 + r)^{-L})} \quad (4)$$

where, A = annual capital cost, I = investment (total capital cost), r = discount rate, and L = lifetime.

The annual net benefit was determined by subtracting the operation and maintenance (O&M) costs (Tables 3 and 4) and the

Table 3
Economic parameters.

	Unit	Value
Lifetime	Years	20
Discount rate	%	10
Working days per year	Days	330
Hours per day	Hours	24
Annual maintenance cost	% of Capital cost	3.5

Table 2
Costs associated to components required for AwR.

Component	Quantity ⁱ	Base cost ⁱ (€ ₂₀₁₂)	Base scale ⁱ		Scaling factor
			Value	Unit	
Absorption column (tank) ^a	1	17,417	250	Nm ³ /h biogas processed	0.67
Absorption column (packing) ^b	1	17,917	250	Nm ³ /h biogas processed	1
Stir tank ^c	4	8000	2000	l	0.67
Compressor ^d	1	10,000	250	Nm ³ /h gas intake	0.67
Pump A ^e	8	3000	0.18	kW _e	0.72
Pump B ^e	2	3000	0.28	kW _e	0.72
Pump C ^e	1	3000	1.18	kW _e	0.72
Filter (pre-treatment) ^f	1	205,500	1	m ² membrane surface	1
Filter (carbonation) ^f	1	151,650	0.64	m ² membrane surface	1
Filter (final treatment) ^f	1	157,770	0.64	m ² membrane surface	1
Conveyer belt ^g	3	10,000	250	Nm ³ /h biogas processed	0.62
Pipes ^h	1	16,500	250	Nm ³ /h biogas processed	0.65

^a Scaling factor from Ref. [30].

^b It is assumed that the required packing material increases linearly as the volume treated increases.

^c Volume includes the stirrers. Scaling factor from Ref. [30].

^d Although efficiency is unknown, we still assume that efficiency remains constant with scaling. Scaling factor from Ref. [31].

^e Pumps are based on a flow rate of 2000–3000 l/h. Assumed capacity of up to 24 kW therefore only one pump is required. Scaled size is linear as we assume that the efficiency of the pump stays the same as the size is relatively small. The difference in energy input for the pumps is due to the different viscosities of the liquids [26]. Scaling factor from Ref. [32].

^f The cost difference between the three filters is a result of the different size requirements for the membrane used. This membrane accounts for roughly 50% of the total cost of each filter [26]. Scaling factor of 1 selected as membrane capacity is linear to the surface area of the membrane [33,34].

^g Technical analysis was not performed for this component, therefore base scale based on processed biogas [26]. Scaling factor from Ref. [35].

^h A specific technical analysis was not performed and the cost of the pipes was assumed to be 50% of the pumps [26]. Scaling based on [32].

ⁱ [16,26].

Table 4
Operation costs and incomes of AwR for a 250 Nm³ facility.

Operational costs and incomes	Yearly consumption/production		Costs
	Quantity ⁱ	Unit	
Expenses			
Electricity ^a	899,237	kWh	0.11 € ₂₀₁₂ /kWh
NaOH ^b	1,219,680	kg	0.79 € ₂₀₁₂ /kg
APC final disposal ^c	11,967	t	58.74 € ₂₀₁₂ /t
Water ^d	61,451	m ³	1.21 € ₂₀₁₂ /m ³
Wastewater treatment ^c	39,236	t	48.52 € ₂₀₁₂ /t
Labour ^e	1	Person*y	46,828 € ₂₀₁₂ /person*y
Income			
APC acceptance ^c	8870	t	97.90 € ₂₀₁₂ /t
Biomethane sold to gas grid ^f (SNG-Grid)	13,067,735	kWh	0.02 € ₂₀₁₂ /kWh
Biomethane sold as vehicle fuel ^g (SNG-Vehicle)	13,067,735	kWh	0.05 € ₂₀₁₂ /kWh
Electricity sold from direct burning ^h (BG-Electricity)	4,818,220	kWh	0.05 € ₂₀₁₂ /kWh

^a Based on industrial price 5 year average between 2008 and 2012 [36]. Price associated with consumption of between 500 MWh and 2000 MWh.

^b Price constantly fluctuates; approximation based on consultation with sellers [37,38].

^c Price includes transport. From consultation with treatment facility [39].

^d Taken from Ref. [40].

^e Assumed current staff at landfill can perform all activities. One professional staff hired with specific knowledge about the technology [41]. This aspect may be an over-assumption as proper training of the staff, with periodical visits may be sufficient.

^f Price of natural gas based on lowest price for industrial consumer, based on annual consumption of over 4 PJ. Price obtained by 5 year average of 2008–2012 [42].

^g Price of natural gas based on price for domestic consumer, based on annual consumption of over 200 GJ. Price obtained by 5 year average of 2008–2012 [43].

^h Price of electricity based on lowest price for industrial consumer, based on annual consumption of over 150,000 MWh. Price obtained by 5 year average of 2008–2012 [36].

ⁱ The quantities related to the yearly expenses and the income from APC acceptance from: Ref. [16].

annual capital recovery from the total annual income. The net present value (NPV), which is a measure of the current value of future incomes and expenses and therefore determines the profitability of an investment, was calculated using equation (5) [27,28].

$$NPV = -I + \sum_{y=0}^L \frac{B_y - C_y}{(1+r)^y} \quad (5)$$

where I = investment (total capital cost), B = annual income, C = annual costs (excluding capital recovery), r = discount rate, L = lifetime and y = year.

Table 4 defines all of the operational inputs and outputs for a 250 Nm³/h biogas upgrading facility along with the yearly quantity and their costs per unit. Linear scaling was applied to determine the same for the 1000 and 5000 Nm³/h plant, with the exception of personnel, which was assumed to be the same for all three sized plants. Data on the quantities of the inputs and the APC residues acceptance came from Lombardi and Carnevale [16]. The same source was used to calculate the annual biomethane and electricity output in kWh. The costs associated with each input and output came from literature reviews and personal communications with companies and experts.

In order to ensure comparability between data all costs were adjusted to €₂₀₁₂ using historical inflation/deflation values [44–47]. Currencies which had to be converted to Euros were first deflated/inflated to 2012, and then an exchange rate was applied [48,49].

2.4. Additional associated costs

2.4.1. Pre-cleaning

There are different technologies that can remove H₂S [2]. A literature review suggested that a liquid scavenger is the optimal method for the H₂S concentration in the biogas [24,50]. The total capital cost and annual operation and maintenance (O&M) costs can be found in Table 5.

2.4.2. Scenario 1 – SNG-Grid

Apart from the pre-cleaning and upgrading there are fees associated with connecting the biomethane to the natural gas grid. These costs include the capital and O&M associated with preparing the gas for grid injection (compressors, odorizers, control valves, flow meters, sensors and other monitoring equipment) and the pipeline to connect to the natural gas grid [51].

The EC directive 2009/28/EC states that access to the gas grid to any producers of biomethane is guaranteed [52]. Although Spanish regulations state that the gas producer is responsible for monitoring the quality of the gas before injection, it does not refer directly to the actual connection costs [53]. In other countries it was found that the costs associated with the connection (pipeline, injection plant and O&M) would depend on the contract between the biomethane producer and the distributor [54–56]. Therefore for the purposes of this study a conservative scenario was assumed whereby all the costs are allocated to the landfill.

A literature search found that the capital costs for the connection has many variables and ranges from approximately 48,000 €₂₀₁₂ to 1,000,000 €₂₀₁₂ [1,51,56]. This cost can increase if connections over 1 km are required and if more treatment is needed to prepare the gas for injection as additional equipment is required [51,56]. The average price of a simple connection to the gas grid was found to be around 60,000 \$CAD₂₀₀₈, or 49,240 €₂₀₁₂, for a 240 Nm³/h biogas facility [51]. This includes basic equipment such as flow meters, odorizers and valves; therefore a scaling factor of 0.7 was applied [16]. This cost only includes a short pipe connection, therefore it was necessary to include an additional pipeline at the following prices: 209,000 €₂₀₁₂/km_{pipeline} for the 250 Nm³/h facility, 339,000 €₂₀₁₂/km_{pipeline} for the 1000 Nm³/h facility, and 760,000 €₂₀₁₂/km_{pipeline} for the 5000 Nm³/h facility [57]. It was assumed that landfills as well as main natural gas lines are found outside of cities, therefore in this study a distance of 1 km between the upgrading site and the gas grid injection site was selected. Similar to the upgrading facility, annual O&M costs of 3.5% of the capital costs are assumed.

An MSWI pays the landfill to accept the APC residues as hazardous waste. After the upgrading process the carbonated APC residues are of a more stable quality as they leach less heavy metals, and can therefore be considered as a non-hazardous waste [11]. After upgrading, the landfill sends the carbonated APC for treatment and disposal. Due to the new classification of the waste, the disposal cost is lower than what the MSWI paid to the landfill to accept the APC residues. Therefore, income comes from both the sale of biomethane and also the treatment of APC residues from upgrading hazardous waste to non-hazardous waste (see Table 4).

Table 5
Costs associated with pre-cleaning H₂S. Prices in €₂₀₁₂.

	Unit			
Biogas generation rate	Nm ³ /h	250	1000	5000
Investment cost	€	19,367	28,534	77,469
Annual O&M	€/y	2235	10,268	111,770

Source: Refs. [24,50].

2.4.3. Scenario 2 – SNG-Vehicle

The landfill takes on the cost of the biogas pre-cleaning and upgrading equipment. In some cases an external company would purchase the biomethane and bring it to a filling station, though for this study it is assumed that the landfill is responsible for the capital and O&M costs involved for a filling station located 2 km from the landfill. The costs for the pipeline required to transport the biomethane to the filling station was assumed to be the same as in SNG-Grid, therefore 209,000 €₂₀₁₂/km_{pipeline} for the 250 Nm³/h facility, 339,000 €₂₀₁₂/km_{pipeline} for the 1000 Nm³/h facility, and 760,000 €₂₀₁₂/km_{pipeline} for the 5000 Nm³/h facility [57]. The costs associated with a compressed natural gas filling station were determined to be 30 €₂₀₁₂/MWh_{biogas} for the infrastructure and 5 €₂₀₁₂/MWh_{biogas} for the O&M [58]. These costs are comparable to values found in literature [1,59,60].

Income comes from the sale of biomethane as vehicle fuel and the treatment of APC residues from hazardous waste to non-hazardous waste (see Table 4).

2.4.4. Scenario 3 – BG-Electricity

The landfill takes on the cost of pre-cleaning equipment as well as the gas generator. Data for the generator was obtained from personal communication with a generator manufacturer [61]. The prices were given for the 250 Nm³/h and 1000 Nm³/h sized generator. The 5000 Nm³/h gas generator price was not provided therefore it was estimated by deriving a scaling factor based on the previous two capacities.

The cost of the connection to the electricity grid is the responsibility of the producer [62]. It is assumed that a landfill would already be equipped with a transformer; therefore the distance selected was 500 m. Through consultations with experts it was determined that the connection cost is approximately 150,000 €₂₀₁₃/km [63].

Income comes from the sale of electricity (see Table 4).

2.4.5. Feed in tariffs

Feed in tariffs were set in 2007 in order to encourage the production of renewable energy in Spain [62], though due to economic downturns these tariffs were suspended for future renewable energy producers in 2012 [64] and retroactively eliminated in 2013 [65]. These tariffs only accounted for electricity produced and did not pertain to biomethane production. In this study we did not account for any tariffs in any scenario as their application and prices are not yet known.

2.4.6. Specific costs

This study looked at the specific cost of each scenario per (i) m³ of biogas processed; (ii), kWh of biomethane, and (iii) CO₂ reduced emissions. The costs were calculated using equation (6).

$$SC_i = \frac{A + C - B}{U_i} \quad (6)$$

where SC = specific cost, *i* = indicator under study, *A* = annual capita cost (eq. (4)), *C* = annual costs, *B* = annual benefits, *U* = annual total of indicator under study, for example the annual total m³ of biogas [28].

For the specific cost of CO₂ reduction in SNG-Grid and SNG-Vehicle, two factors were taken into account. Firstly, the amount of CO₂ stored by the biogas upgrading technology was calculated. This was determined by taking the CO₂ that is found in the biomethane stream (2% of the total), and subtracting that from the total CO₂ input. Secondly, the amount of reduced methane emissions from the landfill was determined (see Table 1). This methane is normally accounted as part of the GHG emissions of a landfill [6]

and therefore its mitigation could be considered as a savings and therefore a source for CO₂ credit. The global warming potential of 1 t of CH₄ over 100 years is equivalent to 34 t of CO₂-eq [4]. The sum of these two factors was counted as reduced emissions. This value, along with equation (6), was used to determine the CO₂ reduction cost, in other words the carbon credit required to break-even.

In BG-Electricity the on-site gas generator directly burns the biogas, thereby producing CO₂. This physical amount is subtracted from the total CO₂ savings associated with methane emission reduction. This subtraction was not included to the CO₂ credit for SNG-Grid and SNG-Vehicle as the associated final end use falls outside of the system of study. Equation (7) shows that the combustion of 1 mol CH₄ produces 1 mol CO₂.



Landfills do not currently enter into the EU ETS (European emissions trading scheme), however it was decided to include the CO₂ reduction cost. Europe wants to keep reducing its emissions and has already put legislation in place with the aim of reducing emission in landfills (Landfill Directive 1999/31/EC [5]). As well, landfill emissions are reported in the UNFCCC country reports. Therefore it can be considered a safe assumption that landfills will eventually be included.

3. Results and discussion

The total annual costs, incomes and net benefit of each scenario can be found in Table 6. As seen, the scenarios that utilize biogas upgrading have an annual loss of between 2.6 and 53 million €₂₀₁₂, while BG-Electricity receives an income of between 0.2 and 5 million €₂₀₁₂. Between SNG-Grid and SNG-Vehicle, the capital costs of connecting to the natural gas grid are lower than the costs associated with the filling station, but the potential income from the filling station is higher compared to selling to the grid. This means that SNG-Vehicle has an annual loss that is 0.1–3.2 million €₂₀₁₂ less than SNG-Grid.

With the specific cost it is possible to see that if CO₂ credit were to be applied, the pricing for the 250 Nm³/h scale would have to be 99 €/t CO₂ in order to break-even for SNG-Grid and 94 €/t CO₂ for SNG-Vehicle. This is quite high compared to the average CO₂ price for EU ETS during 2012, of around 7 €₂₀₁₂/t CO₂ [66] (average price from January 1st to December 31st 2012). Also it was determined that in order for SNG-Grid to obtain a profit on the sale of biomethane it has to be sold for around 0.21 €₂₀₁₂/kWh, which is a tenfold increase over the assumed price of 0.02 €₂₀₁₂/kWh. In SNG-Vehicle, the sale price would have to be above 0.20 €₂₀₁₂/kWh, which is four times higher than the assumed price of 0.05 €₂₀₁₂/kWh. Therefore, large cost reductions are needed if a business case is to be found.

In SNG-Grid and SNG-Vehicle, the costs of biogas upgrading appear as the key component of the total cost figures (in both scenarios it accounts for over 96% of the annual costs).

The size of the upgrading facility does not play a large role in decreasing the costs as the specific cost per m³ biogas processed decreases from 1.40 €₂₀₁₂ for a 250 Nm³/h sized facility to 1.35 €₂₀₁₂ for 5000 Nm³/h for SNG-Grid and from 1.33 €₂₀₁₂ for a 250 Nm³/h sized facility to 1.27 €₂₀₁₂ for 5000 Nm³/h for SNG-Vehicle. This is due to the fact that the main costs for SNG-Grid and SNG-Vehicle come from the operational costs, which is linear.

3.1. Upgrading technology

Table 7 shows that the upgrading step, AwR, was found to have a cost of around 2.80 €₂₀₁₂/m³ of biomethane. This is a significant

Table 6Total costs associated with each scenario. Prices in €₂₀₁₂.

	Unit	SNG-Grid			SNG-Vehicle			BG-Electricity		
Biogas generation rate	Nm ³ /h	250	1000	5000	250	1000	5000	250	1000	5000
Annual costs ^a	M€/yr	3.96	15.60	77.54	4.11	16.14	80.19	0.04	0.07	0.24
of which AwR	M€/yr	3.93	15.53	77.28	3.93	15.53	77.28			
of which pre-cleaning	M€/yr	0.004	0.013	0.12	0.004	0.013	0.12	0.004	0.013	0.12
of which infrastructure ^b	M€/yr	0.03	0.06	0.14	0.18	0.60	2.80	0.03	0.06	0.12
Annual income	M€/yr	1.2	4.8	23.9	1.5	5.9	29.7	0.25	0.99	5.0
Annual net benefits	M€/yr	−2.8	−10.8	−53.6	−2.6	−10.2	−50.5	0.21	0.93	4.7
NPV	M€	−23.3	−91.7	−455.9	−22.3	−86.8	−429.7	1.89	7.96	40.4
Specific costs ^c										
Biogas processed	€/m ³	1.40	1.37	1.35	1.33	1.29	1.27	−0.11	−0.12	−0.12
Production costs ^d	€/kWh	0.21	0.21	0.21	0.20	0.20	0.19	−0.04	−0.05	−0.05
CO ₂ eq. reduction costs	€/t CO ₂	99	97	96	94	92	91	−9	−9	−10
CO ₂ eq. avoided	kt CO ₂ /yr	27.83	111.3	556.6	27.83	111.3	556.6	24.40	97.62	488.1

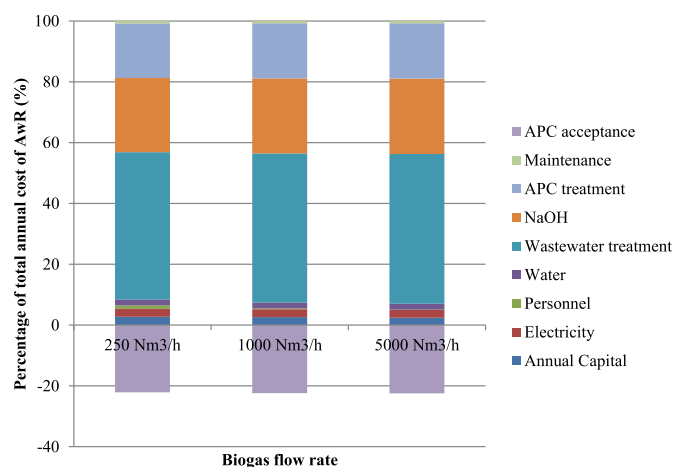
^a Includes annual capital and O&M.^b Infrastructure refers to: for SNG-Grid the treatment and pipeline for connection to the grid, for SNG-Vehicle the CNG (compressed natural gas) filling station and pipeline, and for BG-Electricity the gas generator and the connection to the grid.^c Based on annual cost.^d SNG-Grid and SNG-Vehicle relate to biomethane generated and BG-Electricity to direct electricity production.

difference from other upgrading technologies that report a cost of between 0.11 and 0.40 €_{2007–2009}/m³ of biomethane for a facility between 200 and 300 Nm³/h [67], which inflated to 2012 would be around 0.12–0.43 €₂₀₁₂/m³. In order for SNG-Grid to be profitable, the AwR technology would have to reach a specific cost below 1.08 €₂₀₁₂/m³ of biomethane, or a reduction of 70%. For SNG-Vehicle a slightly smaller reduction of 65% (or 1.23 €₂₀₁₂/m³) would be needed. Therefore, if the specific cost of the AwR approaches those of other upgrading technologies, such as pressure swing adsorption and cryogenic separation then it could be possible to obtain a profit.

Table 7Capital and O&M costs of AwR. All prices in €₂₀₁₂.

	Unit	Biogas upgrading plant		
		250 Nm ³ /h	1000 Nm ³ /h	5000 Nm ³ /h
Capital cost	M€	0.921	3.422	1.603
Annual capital	M€/y	0.108	0.402	1.883
Total operational costs	M€/y	3.786	15.00	74.84
Electricity	M€/y	0.101	0.403	2.015
NaOH	M€/y	0.958	3.832	19.16
APC final disposal	M€/y	0.703	2.812	14.06
Water	M€/y	0.074	0.297	1.483
Wastewater treatment	M€/y	1.904	7.615	38.07
Labour	M€/y	0.047	0.047	0.047
Annual maintenance	M€/y	0.032	0.119	0.561
Total annual cost (before income)	M€/y	3.927	15.53	77.28
Income from APC	M€/y	0.868	3.474	17.37
Total annual cost	M€/y	3.058	12.05	59.91
Specific annual cost of AwR				
Biogas processed	€/m ³	1.54	1.52	1.51
Biomethane generated	€/m ³	2.80	2.76	2.74
Biomethane generated	€/kWh	0.234	0.231	0.299
Specific annual cost of AwR, based on capital cost				
Biogas processed	€/m ³	0.47	0.43	0.40
Biomethane generated	€/m ³	0.84	0.78	0.73
Biomethane generated	€/kWh	0.07	0.07	0.06

A breakdown of the total annual costs of AwR, without including the income, is given in Fig. 3 (as well as Table 7). It is clear that the wastewater treatment, NaOH requirements and the disposal of the APC residues have the highest contributions to the overall costs. The APC residues that are used are considered hazardous waste before the upgrading and non-hazardous after the upgrading. The price at which APC residues are accepted, which is an income, is around 97.90 €₂₀₁₂/t while the price the landfill would in turn have to pay for its treatment of the non-hazardous waste is 58.74 €₂₀₂₅/t. This cannot be viewed as a straightforward profit of 39.16 €₂₀₁₂/t since for every t of APC residue accepted 1.35 t of carbonated APC residue is obtained after upgrading. In order to ensure a profit from the use of APC residues the following condition must be met: €_H > 1.35 × €_{NH}, where €_H is the price of the hazardous waste, €_{NH} is the price of the non-hazardous waste. In this study these conditions are met, which means that the APC residue provides an overall profit at around 19 €₂₀₁₂ per t of APC residue used.

**Fig. 3.** Annual cost breakdown of AwR technology at different sizes.

Therefore the main costs of AwR come from NaOH (25%) and the treatment of wastewater (49%). The treatment of wastewater from the biogas upgrading technology is necessary as preliminary tests found that there are heavy metals and chlorine that end up in the water from the washing of APC residues. The presence of such compounds means that wastewater treatment imposes a higher cost. The APC residues that were tested came from specific incinerators in Italy and as the composition of the residues is inherent to the waste that is incinerated, the concentration of contaminants in the water may change, thereby possibly reducing the need for treatment. A sensitivity analysis on the price of NaOH and wastewater treatment was conducted and can be found in Section 3.2.

The annual capital cost of the biogas upgrading equipment is around 2% of the total costs (excluding income), though if the prices of NaOH and wastewater treatment can be reduced then this capital would play a more significant role. The specific capital cost of the AwR did not decrease with size, as was expected. The scaling factor was found to be almost linear at 0.95, as opposed to 0.7 which was suggested by the developers [16]. The largest expense came from the equipment for the three filtering steps (56% for 250 Nm³/h, 60% for 1000 Nm³/h, and 64% for 5000 Nm³/h) followed by the building that houses the AwR (14%). The membrane has a scaling factor of 1, which results in almost linear scaling for the entire AwR equipment. Therefore the way to considerably reduce capital costs is through the filtering system. The technology currently uses membrane filters, which is a new technology. With advances and increasing market it is likely that the costs would eventually go down, though it would not be enough to make the case studies break-even as the O&M costs are still significant. Even if there were no membrane costs, in order to break-even it would be required to

reduce the O&M costs by around 86% for SNG-Grid and by around 82% for SNG-Vehicle.

3.2. Sensitivity analyses

In this section various sensitivity analyses were conducted. First, a general analysis on different variables was assessed. This was followed by a more in-depth sensitivity analysis on the prices associated with NaOH and wastewater treatment, and on the distances and costs associated with the distribution of biomethane and electricity for the three scenarios. Lastly, a sensitivity analysis was conducted on the allocation of CO₂ credits.

A sensitivity analysis was conducted on some variables for SNG-Grid and SNG-Vehicle. Figs. 4 and 5 show uncertainties in operational prices, such as the treatment of wastewater and the price of NaOH, can have a significant negative impact on the total annual net benefit. Aspects related to infrastructure, such as the discount rate and the pipeline distance, also result in a larger annual net loss when these variables are increased, however their impact is less significant compared to the impact from operational costs. The largest costs in the O&M can be attributed to the price of NaOH and of the wastewater treatment, both of which can and do change over time. Therefore, a sensitivity analysis was performed in order to see at which price for NaOH and wastewater treatment the plant would break-even. It was found that, since both of the costs are significant, eliminating one cost is not sufficient to gain a profit in either SNG-Grid or SNG-Vehicle. Therefore, both would need to be reduced as shown in Fig. 6. In order for SNG-Grid to break-even, the cost of NaOH would need to be reduced by at least 81–90% from 0.79 €/2012/kg, if the wastewater treatment would be for free. If the

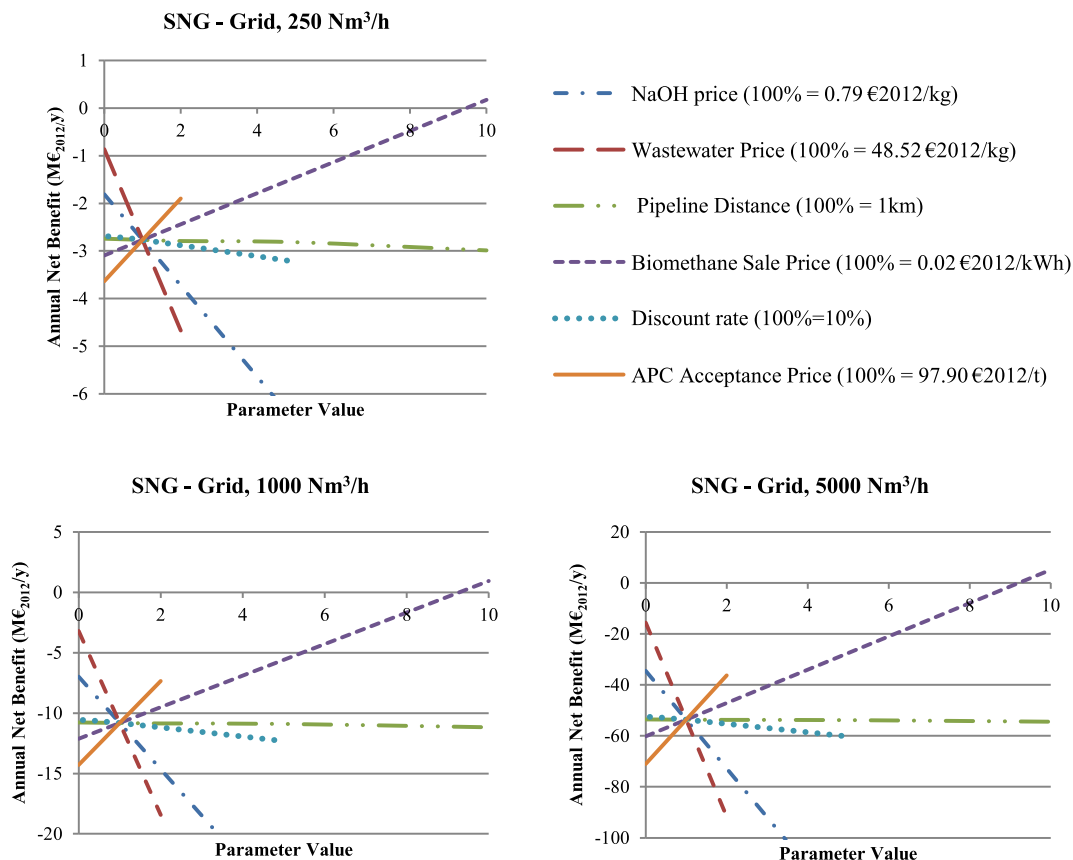


Fig. 4. Sensitivity analysis of SNG-Grid.

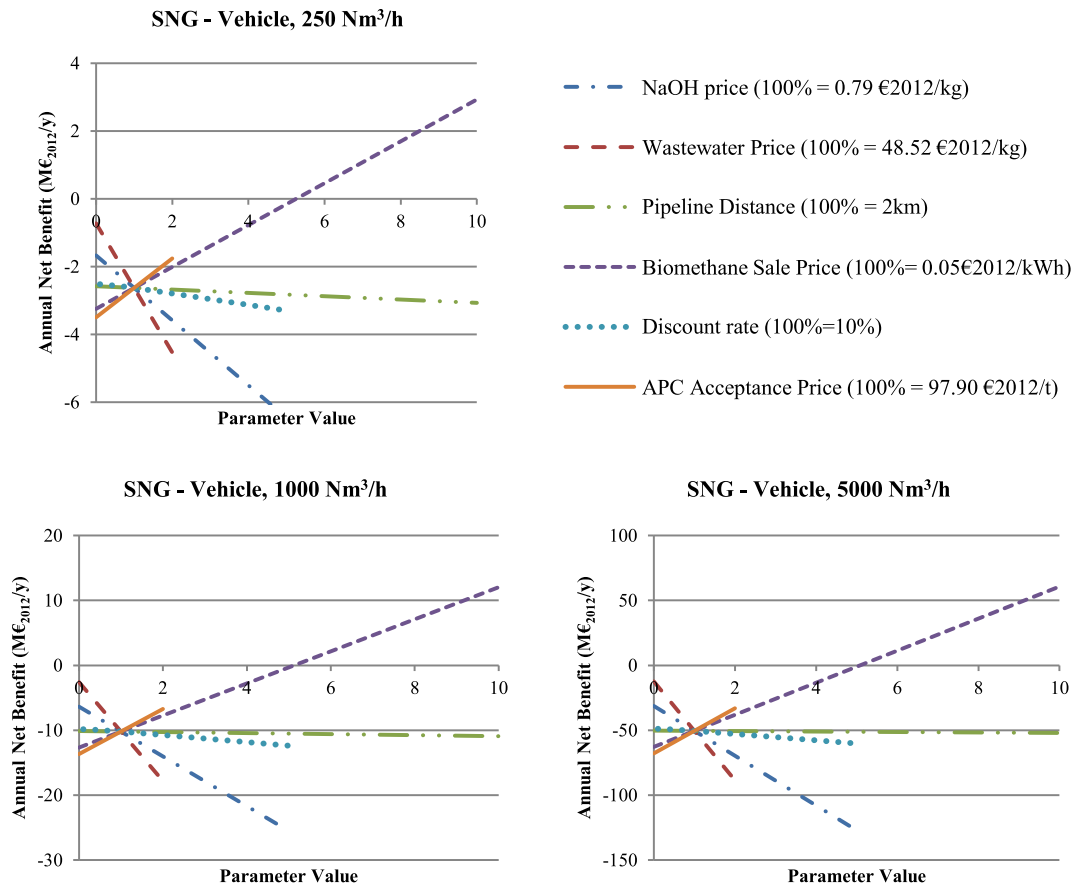


Fig. 5. Sensitivity analysis of SNG-Vehicle.

NaOH cost was reduced to zero then the wastewater treatment price would have to be reduced by at least 91–95% from 48.52 €₂₀₁₂/t in order to break-even. Since it is not feasible to eliminate the cost of either NaOH or of wastewater treatment, it would be necessary to find a mid-point between the two costs. In Fig. 6 the area below each line denotes prices at which an annual profit can be obtained. SNG-Vehicle does present a more optimistic case in which the NaOH would have to be reduced by 65–75% (if wastewater treatment is zero) or the wastewater treatment must be reduced by 82–88% (if NaOH price is zero). While the cost reductions are less than in SNG-Grid both scenarios do require significant price cuts which may be difficult to achieve. Therefore

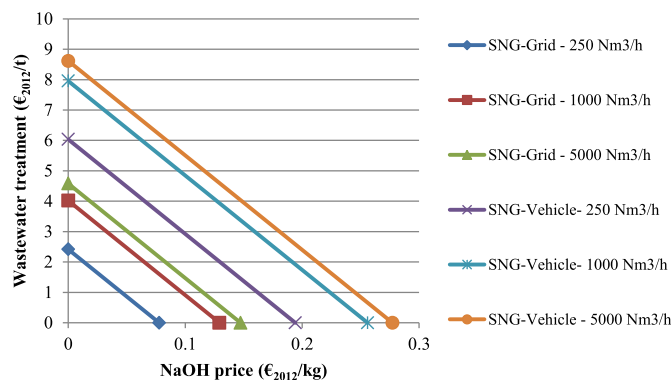


Fig. 6. Cost reductions of NaOH and wastewater treatment. Line means annual benefit = 0. Above line means annual loss and below signifies annual profit.

focus for cost reductions should not be placed solely on these two elements but rather in combination in other areas such as the filter used in the AwR process, increasing the price at which biomethane is sold or a carbon credit.

With such high prices for wastewater treatment, the landfill would most likely opt to invest in increasing the capacity of its existing wastewater treatment facility (used for leachates). If the AwR is not installed on a landfill or on a site where wastewater is not treated then a new facility may have to be built. Further research is required to estimate the impact of on-site wastewater treatment.

A detailed sensitivity analysis was done for the distance between the biogas upgrading facility and the natural gas grid in SNG-Grid and the natural gas fuelling station in SNG-Vehicle, which was assumed to be 1 km and 2 km respectively. It was determined that the impact of the pipeline distance was relatively minor. While the price of the pipeline increases with the size of the facility, it was determined that the smaller sized facility is more sensitive to distance. For instance, if the distances increased to 10 km, the annual cost of a 250 Nm³/h facility increases by 8% in SNG-Grid, while in SNG-Vehicle the price increases by 7.5%. The 1000 Nm³/h facility increases the annual costs of SNG-Grid by 3.31% and SNG-Vehicle by 3.12%, while the 5000 Nm³/h facility sees an increase of less than 1.5% for both scenarios. However when the larger distance of 50 km is applied, the increase in price is more noticeable. For both scenarios the 250 Nm³/h facilities sees a price increase of roughly 44%, while the 5000 Nm³/h facility only sees an increase of around 8%.

Meanwhile, BG-Electricity was found to be more sensitive to the distance involved for the connection from the facility to the

electricity grid. Currently, BG-Electricity generates an annual income when a connection distance of 0.5 km is applied. If this was increased to 10 km then the income would decrease by 78% for a 250 Nm³/h facility, by 18% for a 1000 Nm³/h facility and by 3.5% for a 5000 Nm³/h facility. At a distance of 13 km the 250 Nm³/h facility would no longer generate an annual profit. This point would be reached at 54 km and at 272 km for a 1000 and 5000 Nm³/h facility respectively. In the original assessment it was assumed that the landfill would be responsible for the cost of distributing the biomethane after its upgrading, or in the case of BG-Electricity, the cost to connect to the electricity network. An analysis was run to determine how the annual costs would change if the connection costs would be taken on by a second or third party, as opposed to the landfill. For SNG-Grid annual costs could drop by less than 1% if the gas distributor took on the connection costs. As the infrastructure and connection costs are higher for the vehicle filling station, eliminating these costs have a slightly larger impact. In this case the annual costs drop by less than 2%. BG-Electricity also sees a small impact with reductions between 4% and 0.2% for the 250 and 5000 Nm³/h plant respectively.

In the assessment it was assumed that the CO₂ credit which the upgrading technology obtains would be applied solely to the technology itself. However, it may be possible that landfills will be required to pay a penalty for landfill emissions. If this is the case then it is of interest to know whether treating the biogas through upgrading can reduce the costs for the landfill. This sensitivity analysis was conducted at the price of 7 €/t CO₂ [66]. At this price, it was found that both SNG-Grid and SNG-Vehicle have an annual cost that is around 16% higher than what a landfill would pay in penalties if it doesn't treat biogas. Table 8 shows that under this cost scheme BG-Electricity lowers the cost that the landfill has to pay by between 0.6 and 11 M€. This analysis was also applied to flaring, which is another biogas management option that is not profit-oriented, yet is often enforced by law as the minimal treatment [5]. Under the applied CO₂ credit price it was noted that flaring also reduces the overall costs of the landfill, though not as much as BG-Electricity which lowers costs by 2% compared to flaring. The costs listed in Table 8 are applicable to all biogas collection rates. Landfills do not collect 100% of the biogas they emit, therefore if a landfill collects 1% or 50% of their biogas, it was found that the price difference between letting all of the biogas escape and treating the collected gas will differ by that exact amount listed in Table 8. Another way to look at it that if under the scenario of BG-Electricity a landfill collects and treats only 1% of its biogas then the landfill will still have to pay for their emissions. If the 1% corresponds to a 250 Nm³/h facility then they would be penalized almost 15 M€ for the remaining uncaptured 99%, while only obtaining a profit of around 0.4 M€ (for the CO₂ credit and sale of electricity in BG-Electricity). However if the landfill can capture 50% of its biogas then BG-Electricity will generate an income as they would be penalized 0.1 M€ but then would still obtain a profit of 0.4 M€. It was found under this scenario that BG-Electricity would break-even when a landfill collects around 25% of its landfill gas, while flaring would only break-even at around 50%.

Table 8
Reduction or savings of landfill costs due to biogas emissions through the addition of various treatment options, at 7 €/t CO₂ (M€/y).

	250 Nm ³ /h	1000 Nm ³ /h	5000 Nm ³ /h
SNG-Grid	2.5	9.6	47.7
SNG-Vehicle	2.3	9.0	44.5
BG-Electricity	−0.6	−2.2	−11.1
Flaring	−0.3	−1.2	−6.1

It was found that in order for SNG-Grid and SNG-Vehicle to have an annual cost that is lower than not treating the gas, the price per tonne would have to reach between 63 and 65 €/t CO₂ for SNG-Grid and between 60 and 62 €/t CO₂ for SNG-Vehicle. Fig. 7 show how the price range changes over biogas plant size.

4. Conclusion

This study aimed to determine whether it is economically feasible to use AwR to generate biomethane from landfill biogas and to sell the biomethane to the natural gas grid (SNG-Grid) or as vehicle fuel (SNG-Vehicle). It was also compared to directly generating electricity from the biogas (BG-Electricity).

Of the three case scenarios that were investigated, only the direct burning of biogas for electricity makes a profit of 214,000 €/2012/y for a 250 Nm³/h biogas flow rate. For a plant of the same size, the application of this technique can reduce the landfill GHG emissions by around 24,000 t CO₂ eq./y, which increases to around 490,000 t CO₂ eq./y for a 5000 Nm³/h facility (if one does not include the CO₂ impact of the process itself). If the biogas is first upgraded, then the GHG emissions that can potentially be reduced is increased to around 26,000 and 520,000 t CO₂ eq./y, for a 250 and 5000 Nm³/h facility respectively. Despite the higher GHG savings the two other cases studies, which involve biogas upgrading using AwR, are not economically feasible under the circumstances of this study. This is due to the high O&M costs of the upgrading process itself, which is mainly attributed to the cost of NaOH (25%) and wastewater treatment (49%).

In order for the cost of SNG-Grid and SNG-Vehicle to break-even it would be necessary to either sell biomethane at a price of around 0.12–0.20 €/kWh or sell carbon credit at a price of over 99 €/t CO₂. However, it is advisable to first reduce the price of the process itself through a combination of improving the selected de-watering system, increasing the profit from APC, and reducing the required amount and/or the cost of the NaOH and wastewater treatment. These modifications, along with possible feed-in tariffs from the sale of biomethane and CO₂ credits, would reduce the cost of AwR and make it possible to profit from the sale of upgraded biogas. Selling upgraded biomethane for use as vehicle fuel is slightly more cost effective than injection into the gas grid as the biomethane can be sold at a higher price. However, if feed-in tariffs for biomethane are implemented then the prices may even out, thus making injection into the gas grid a more desirable option. The filling station may also have more long term potential as it could obtain biomethane from other sources once the landfill stops emitting

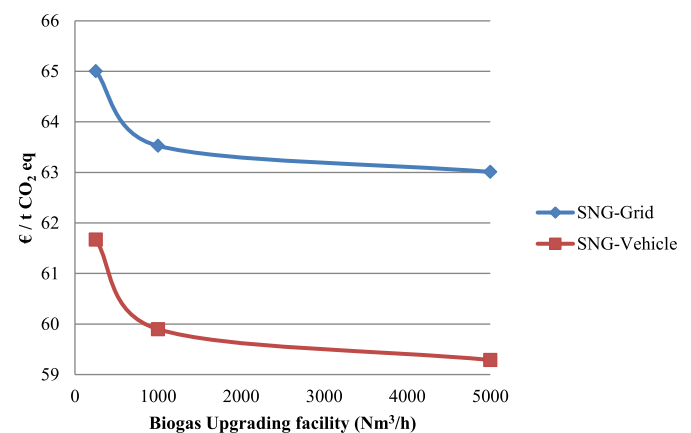


Fig. 7. Price at which upgrading scenarios have the same annual cost of not treating biogas in landfills.

sufficient methane. However, location is an important factor to consider as costs would increase the further away the filling station is from the upgrading site. This is also an important factor for the injection into the gas grid as the gas distributor determines where the gas can be injected. If distance proves to be the limiting factor for the biogas upgrading facilities, then other options should be explored such as symbiosis with a neighbouring industry or even localized distribution to residents in a neighbouring city for use as cooking fuel.

Biogas upgrading technologies provide an alternative to reduce GHG emissions as it limits the methane emissions from landfills and could potentially provide an income due to the sale of biomethane. In particular, the application of carbon mineralization to biogas upgrading has a large potential due to the additional reduction of GHG emissions through direct CO₂ storage which is an added environmental advantage. However, in order for the AwR process to reach commercialization, significant reductions in the operating costs are required as it is currently not economically feasible.

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