Base rates in the SDE+ 2013 Final Advice

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Abstract

On assignment of the Dutch Ministry of Economic Affairs, Agriculture and Innovation, ECN and DNV KEMA have studied the cost of renewable energy production. This cost assessment for various categories is part of the advice on the subsidy base for the feed-in support scheme SDE+. This report contains the advice on the cost of projects in the Netherlands targeted for realization in 2013. The advice covers technologies for the production of green gas, biogas, renewable electricity and renewable heat.

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Summary

The Dutch ministry of Economic Affairs, Agriculture and Innovation asked ECN and DNV KEMA to offer advice on the base rates for 2013. This report presents the final advice, following a draft version which was written for a consultation round with market parties. Table 1 shows an overview of the base rates for biomass digestion in this final advice; Table 2 shows the base rates for thermal biomass conversion and Table 3 shows the base rates of the other options.

For some categories, the calculated base rates exceed 15 €ct/kWh resp. 103.53 €ct/Nm3, the upper limit in the SDE+. The base rates of these options, i.e. onshore wind, free tidal current energy, osmosis, green gas from gasification and electricity from manure mono-digestion, have been based on indicative calculations. The cost developments in offshore wind are such that in the coming years the base rate may drop below 15 €ct/kWh. Therefore, more specific attention for this technology is justified in the future.

Table 1: Overview of advised base rates SDE+ 2013 for biomass digestion

	Pg	Hub	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
All-feedstock digestion (stand-alone)	36	No	*Heat*	14.7	[€/GJ]	7000	-
	36	No	*CHP*	26.0	[€/GJ]	8000 / 4000	5739
	34	No	*Green gas*	59.4	[€ct/Nm^3]	8000	-
All-feedstock digestion (hub application)	23,34	Yes	*Heat*	17.7	[€/GJ]	7000	-
	22,34	Yes	*CHP*	29.1	[€/GJ]	8000 / 4000	5741
	24,34	Yes	*Green gas*	66.4	[€ct/Nm^3]	8000	-
Manure co-digestion (stand-alone)	33	No	*Heat*	20.6	[€/GJ]	7000	-
	33	No	*CHP*	31.1	[€/GJ]	8000 / 4000	5732
	31	No	*Green gas*	74.0	[€ct/Nm^3]	8000	-
Manure co-digestion (hub application)	23,31	Yes	*Heat*	21.9	[€/GJ]	7000	-
	22,31	Yes	*CHP*	34.9	[€/GJ]	8000 / 4000	5741
	24,31	Yes	*Green gas*	78.9	[€ct/Nm^3]	8000	-
Manure digestion	30	No	*Heat*	23.1	[€/GJ]	7000	-

	Pg	Hub	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
(stand-alone)	30	No	*Electricity*	23.5	[€ct/kWh]	8000	-
	28	No	*Green gas*	84.0	[€ct/Nm^3]	8000	-
Manure digestion (hub application)	23,28	Yes	*Heat*	25.2	[€/GJ]	7000	-
	22,28	Yes	*CHP*	37.1	[€/GJ]	8000 / 4000	5741
	24,28	Yes	*Green gas*	83.6	[€ct/Nm^3]	8000	-
WWTP (thermal pressure hydrolysis)	27	No	*Electricity*	9.6	[€ct/kWh]	8000	-
WWTP (replacement of gas engine)	25	No	*CHP*	6.4	[€/GJ]	8000 / 4000	5751
	25	No	*Green gas*	31.2	[€ct/Nm^3]	8000	-
	23,25	Yes	*Heat*	2.4	[€/GJ]	7000	-
	24,25	Yes	*Green gas*	20.1	[€ct/Nm^3]	8000	-
All-feedstock digestion (extended life)	43	No	*CHP*	22.5	[€/GJ]	8000 / 4000	5749
All-feedstock digestion (extended life)	24,43	Yes	*Green gas*	56.7	[€ct/Nm^3]	8000	-
All-feedstock digestion (extended life)	23,43	Yes	*Heat*	14.2	[€/GJ]	7000	-
Manure co-digestion (extended life)	43	No	*CHP*	26.4	[€/GJ]	8000 / 4000	5749
Manure co-digestion (extended life)	24,43	Yes	*Green gas*	65.6	[€ct/Nm^3]	8000	-
Manure co-digestion (extended life)	23,43	Yes	*Heat*	17.1	[€/GJ]	7000	-
Heat utilisation existing all-feedstock digestion	40	No	*Heat*	6.3	[€/GJ]	7000	-
Heat utilisation existing manure co-digestion	41	No	*Heat*	8.2	[€/GJ]	4000	-
Heat utilisation in composting	42	No	*Heat*	4.4	[€/GJ]	7000	-

* Note on CHP options: full load hours electricity/full load hours useful heat deployment.

Table 2: Overview of advised base rates SDE+ 2013 for thermal biomass conversion

	Pg	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
Gasification	53	*Green gas*	123.4	[€ct/Nm³]	7500	-
Thermal conversion <(10 MW_e)	37	*CHP*	40.9	[€/GJ]	8000/4000	4241
Thermal conversion (> 10 MW_e)	37	*CHP*	21.8	[€/GJ]	7500/7500	7500
Extended life of incineration plants	44	*CHP*	18.7	[€/GJ]	8000/4000	4429
Boiler fired by solid biomass	38	*Heat*	11.5	[€/GJ]	7000	-
Boiler fired by liquid biomass	39	*Heat*	21.7	[€/GJ]	7000	-
Heat utilisation existing waste incineration plants	40	*Heat*	6.3	[€/GJ]	7000	-
Heat utilisation existing incineration plants	40	*Heat*	6.3	[€/GJ]	7000	-

* Note on CHP options: Full load hours electricity/full load hours useful heat deployment.

Table 3: Overview of advised SDE+ base rates for 2013 for other options

	Pg	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
Geothermal energy and heat						
Deep geothermal energy	49	*Heat*	11.8	[€/GJ]	5500	-
Deep geothermal energy	50	*CHP*	24.0	[€/GJ]	5000 / 4000	4158
Wind energy						
Onshore wind, extremely rich in wind	46	*Electricity*	7.0	[€ct/kWh]	3300	-
Onshore wind, very rich in wind	46	*Electricity*	8.0	[€ct/kWh]	2800	
Onshore wind, rich in wind	46	*Electricity*	9.0	[€ct/kWh]	2400	
Onshore wind, low- wind	46	*Electricity*	9.5	[€ct/kWh]	2200	-
Onshore wind ≥ 6 MW	46	*Electricity*	9.3	[€ct/kWh]	3000	-
Wind in lake	46	*Electricity*	12.2	[€ct/kWh]	3200	-
Offshore wind	54	*Electricity*	16.0	[€ct/kWh]	4000	-
Hydro energy						
Low fall of height (< 5 m)	45	*Electricity*	11.8	[€ct/kWh]	7000	-
Hydropower in existing water management facilities	46	*Electricity*	6.2	[€ct/kWh]	4300	-
Free tidal current energy	55	*Electricity*	25.5	[€ct/kWh]	2800	-
Osmosis	55	*Electricity*	49.3	[€ct/kWh]	8000	-
Solar energy						
Solar PV (> 15 kW_p)	52	*Electricity*	14.8	[€ct/kWh]	1000	-
Solar thermal	51	*Heat*	33.3	[€/GJ]	700	-

* Note on CHP options: full load hours electricity/full load hours heat supply.

1

Introduction

The Dutch Ministry of Economic Affairs, Agriculture and Innovation (EL&I) has asked ECN and DNV KEMA to advise on the height of the base rates for the SDE + scheme for 2013. This report contains the final advice on the base rates. Similar to comparable studies in previous years, ECN and DNV KEMA, in consultation with the ministry, opted for consulting the market about the intended advice. A draft advice was written and used for the consultation (Lensink *et al*., 2012a). The responses received from the market, including some comments by ECN and DNV KEMA, have been collected in (Lensink *et al*, 2012b).

ECN and KEMA advise the ministry on the height of the base rates for the categories that are prescribed by the ministry. The Minister of EL&I decides on the opening of the SDE+ scheme in 2013, on the categories to be opened and on the base rates for the new SDE+ allowances in 2013.

Reading instructions
The starting points of the advice, such as assignment and calculation method, are explained in Chapter 2. Chapter 3 addresses the working method and preconditions such as flanking policy and financial starting points. The feed-in tariff structure of SDE+ is explained in Chapter 4.

The price developments for electricity, gas and biomass are elaborated in Chapter 5. Chapter 6 provides the technical-economic parameters of the renewable energy options per category. Chapter 7 contains the conclusions that provide the basis for the translation into base rates.

2

Process

The draft advice was published on 15 May 2012 to serve as input for the public market consultation. A first step in this process was an information meeting on 7 May 2012 for branch organisations, held at the Dutch Ministry of Economic Affairs, Agriculture and Innovation. This report was used to invite market parties to send a response in writing to ECN.

About 30 written responses have been received. Half of these responses led to a follow-up meeting. Based on the written responses and these follow-up meetings, ECN and DNV KEMA made some changes in the advice.

The process, the advice and the way in which ECN and DNV KEMA have weighed the received market responses have also been subject of an external review by Fraunhofer ISI from Karlsruhe, as requested by the Ministry of EL&I.

3 Working method and starting points

The Dutch Ministry of EL&I requested ECN and DNV KEMA to establish the base rates for the SDE+ scheme for 2013. The advised base rates include the production costs of renewable energy carriers and any scheme-specific surcharges with regard to the closing of electricity and gas contracts. The ministry listed the categories in the request for advice. ECN and DNV KEMA will calculate the production costs of renewable electricity, green gas and renewable heat for all categories. The Minister of EL&I will make the final decision on the opening of categories. Neither the inclusion nor the absence of a category in this report should be read as advice on the possible opening of categories.

The starting points for the calculation have been established in consultations between the ministry and ECN and DNV KEMA. The effectiveness and efficiency of the SDE+ scheme have been taken into account (cf. Van Sambeek *et al*., 2002). This implies that the SDE+ allowance, hence also the base rates, must be sufficiently high to enable the production of renewable electricity, renewable heat and green gas in the categories, but the base rates need not be sufficient for all planned projects. The rule of thumb is that the majority of the projects per category should be able to proceed with these base rates.

Existing law and legislation must be taken into account in the calculation of the production costs, to the extent that they apply generically to the Netherlands. The advice is thus based on policy that will be in force in 2013 (based on decision-making). The production costs are related to projects that are eligible for SDE+ in 2013 and can start as a construction project in 2013 or early 2014. As for the production costs of solar PV, the Ministry of EL&I has indicated that the expected production costs in the second half of 2014 should be taken as starting point The Ministry of EL&I sees to it that the calculated production costs do justice to the provisions of the European Commission in the field of State Aid.

A reference installation has been established for each category. The reference installation is based on a specific technique (or combination of techniques), combined with a common number of full load hours and a reference fuel for the bio-energy categories. ECN and DNV KEMA also consider the reference installation (possibly combined with a reference fuel) suitable for new projects in the category under investigation.

The technical-economic parameters are established for the identified fuel-technique combinations. Based on these parameters, the production costs and base rates are established by means of the stylised cash flow model. This model can be viewed on the ECN website[1].

The SDE+ scheme reimburses the difference between the production costs of renewable electricity, renewable heat and green gas on the one hand and the market price of renewable electricity, renewable heat or green gas on the other hand. The production cost consists of the additional costs of the so-called reference installation to realise the production of renewable electricity, renewable heat or green gas compared to the alternative use of the renewable energy source. Especially in systems using biomass from waste flows or residual products, the definition of 'additional costs', i.e. the system boundary, can significantly influence the calculated biomass costs. Additional costs are calculated for using these flows or products for the production of renewable electricity or green gas. Biomass costs are based on the prices that must be paid to deliver the biomass to the installation. Additional costs are determined by calculating the difference between the above-mentioned biomass prices and the price of biomass if it would not be used for the production of renewable electricity, renewable heat or green gas. All prices mentioned in this report are exclusive of VAT.

For renewable heat categories, the costs are considered that are related to the production of renewable heat. The cost of a heat distribution pipe is included in the investment cost of the project. The heat infrastructure on the demand side, as for example a heat grid, is not part of the costs that are eligible for subsidy. The heat production considered in this advice has bearing on the heat throughput immediately behind the gate of the installation, but before it enters the heat distribution grid. This means that an SDE+ allowance can possibly also apply to internal use of renewable energy, as long as it is not intended for the production process itself.

In view of the financial preconditions, ECN and DNV KEMA were asked by the Ministry to assume a total financial return of 7.8%. This financial yield also needs to be used to cover the preparation costs. The preparation costs are not included in the total investment amount. If the EIA or green soft-loan scheme applied generically to a specific category in the past year, ECN and DNV KEMA need to include this in the final advice. The green scheme assumes a tax benefit of 1%.

For all biomass categories, a subsidy duration of 12 years is assumed, whereas for the other categories this is assumed to be 15 years. The duration of the loan and depreciation periods is assumed to be equal to the subsidy duration. Some of the components of techniques such as hydropower and geothermal have a much longer life in practise than 15 years. Therefore their investment costs are corrected for the

[1] http://www.ecn.nl/nl/units/ps/themas/hernieuwbare-energie/projecten/sde.

residual value of the components after 15 years. In project financing, the lender may want the loan to be repaid in a shorter period of time in practice, e.g. 11 or 14 years. This offers the lender more certainty that the loan will be fully repaid. The total financial yield of 7.8%, however, is considered to be a reasonable compensation for the total risk of the project. The manner in which the risks and returns are divided among the lender and the project developer does not influence the advised base rates under the given starting points.

4

Explanation of premium structure

SDE+: Base rates and correction rates

The SDE+ scheme is a scheme that has a variable or sliding feed-in premium. It is a compensation for exploitation, in which the compensation is basically paid for all renewable energy that is fed into the grid (hence ‘feed-in’). The premium that will be paid is the difference between a *base rate* and a *correction rate*. The base rate covers the production costs of renewable electricity, renewable heat or green gas. The correction rate is established on the basis of real revenue. Every category has its own base rates and correction rates. The base rates are fixed for the duration of the SDE+ decision. The correction rates are calculated every year based on the recent energy prices, whereas the base rate nominally stays the same for all years in the duration of a project.

Base prices

The feed-in premium that is to be paid has been maximised. The premium basically covers the entire unprofitable gap of a production installation, unless the gas, electricity or heat price drops below a certain value, the so-called *base price*. In the SDE+ scheme, this value is set at 2/3rd of the expected correction rates, based on the long-term development of the energy prices. Should the price drop below the calculated level of the base price, the base price will automatically be adopted as correction rate.

Base price premium and transaction costs

The SDE+ scheme reimburses the difference between the production costs and the market price of electricity, gas or heat. In doing so, it is assumed that the supplied renewable energy will also be traded on the market. The transaction cost for closing contracts on energy supply are included in the base rates. They amount to 0.09 €ct/kWh for electricity and are assumed to amount to the same for heat. In the case of green gas, annual costs of €15,000 are calculated for connections to a regional gas grid up to € 350,000 for connection to the high tension grid. The costs attached to the risk of correction rates dropping below the base price are also weighed in the base rates. To this end, a base price premium is calculated that can be considered a kind of insurance premium against low energy prices. The base price premium, which varies from 0 to 0.25 €ct/kWh, increases the base rate.

Correction rates, imbalance and profile factor

For some categories, such as wind energy and solar PV, the correction rates are corrected with an balancing factor or a profile factor. These correction factors are not part of this advice and are therefore not discussed in this report. The correction rates themselves are not a part of this advice either, however the calculation method is elaborated below for the purpose of clarification.

Calculating method correction rates

The correction rates for the various categories in SDE+ are based on different market indices. These are the natural gas price and the electricity prices for base load and peak load and derivatives. In the case of heat and CHP options, the price of heat (partly) determines the correction rate. The prices of heat are derived from the natural gas price and a distinction is made based on the reference situation: gas-fired boiler or CHP. For heat supply via a hub, deep geothermal (heat) and heat utilisation in existing installations, CHP is considered to be the reference (Renewable heat -1 in Table 4). The value of heat for these categories is set at 70% of the natural gas price. The other categories in heat supply have a gas-fired boiler with a 90% efficiency as reference (Renewable heat -2 in Table 4). The Energy Tax (ET) is included in calculations in accordance with the volume of the reference project.

The correction rate is calculated by means of the following equation:

$$\text{Correction rate} = \text{Price index} \times \text{Factor}$$

Table 4 offers an overview of the various calculation variants that apply to the different categories.

Table 4: Calculation method correction rates

	Heat reference	Unit	Price index	Factor
Renewable Heat -1	CHP	[€/GJ]	0.7*(natural gas price + ET)	
Renewable Heat -2	Gas-fired boiler	[€/GJ]	Natural gas price (+ energy tax)/0.9	
CHP	CHP	[€/GJ]	compiled†	
Green gas	-	[€ct/Nm^3]	Natural gas price	
Renewable electr. - Wind	-	[€ct/kWh]	Electr. - Base load	Unbalance factor* wind factor
Renewable electr. - Solar PV		[€ct/kWh]	Electr. - Peak load	Unbalance factor
Renewable electr. - other	-	[€ct/kWh]	Electr. - Base load	

† The price index for CHP is compiled as follows: $Index_{WKK} = \frac{0{,}7(natural\ gas\ price + EB) * W/_K + El.price_{base\ load}}{1 + W/_K}$; in which all prices are expressed in [€/GJ].

Full load hours CHP

For categories with production installations for combined generation of electricity and heat a distinction is made between the heat capacity and the electricity capacity of an installation. In this respect, a distinction is also made between the number of full load hours for heat production and the number of full load hours for electricity production. To offer producers flexibility in varying the ratio between heat and electricity production, installations will get a decision based on the total capacity (nominal electricity capacity plus nominal heat capacity). These nominal capacities need not be realisable at the same time.

The total capacity of an installation has a maximum number of full load hours for which subsidy is paid every year. This maximum number of full load hours is a built-up number of full load hours for electricity and heat, weighed according to the heat-power ratio of the reference installation. This is the average heat-power ratio of the reference installation during production. The maximum number of full load hours for combined generation of electricity and heat, without electricity losses in heat transfer, is calculated as follows:

$$\begin{array}{c}\text{Full load hours for}\\ \text{combined}\\ \text{generation}\end{array} =$$

$$\frac{\begin{array}{c}\text{thermal capacity}\\ \text{reference}\end{array} \times \begin{array}{c}\text{full load hours heat}\\ \text{reference}\end{array} + \begin{array}{c}\text{electrical capacity}\\ \text{reference}\end{array} \times \begin{array}{c}\text{full load hours electricity}\\ \text{reference}\end{array}}{\begin{array}{c}\text{thermal capacity}\\ \text{reference}\end{array} + \begin{array}{c}\text{electrical capacity}\\ \text{reference}\end{array}}$$

Installations using a condensing turbine[2] may have a deviating CHP ratio during production compared to the CHP ratio based on electrical and thermal capacity of the installation. When these installations produce heat, the electrical capacity decreases.

[2] Installations that use a back pressure turbine have a CHP ratio based on the electrical and thermal capacities of the installation. For these installations the electrical capacity increases proportionally with the heat production. As a consequence, both capacities can be used at the same time. The maximum number of full-load hours for installations with a back pressure turbine is the same for electricity and for heat.

This leads to electricity losses. As a consequence, both capacities cannot be utilised at the same time. The maximum number of full load hours for combined heat and power installations that use a tapped condensing turbine is calculated as follows:

$$\text{Full load hours for combined generation} = \frac{\text{thermal nominal capacity reference} \times \text{full load hours heat reference} + \text{electrical capacity reference at full heat production} \times \text{full load hours heat reference} + \text{max. electrical capacity reference} \times \left(\text{full load hours electricity reference} - \text{full load hours heat reference}\right)}{\text{thermal nominal capacity reference} + \text{electrical nominal capacity reference}}$$

Weighing based on the CHP ratio as described above is also used for determining the base price and the correction rates of the SDE+ scheme.

5

Prices for electricity and biomass

5.1 Electricity prices

The base rates are a measure for the production cost of renewable energy options. The production costs are not directly related to the prices of fossil fuels such as coal, oil and gas. Some installations have an additional energy demand that is not covered by the installation itself. Examples include green gas installations, which use electricity. The average electricity tariff during the operating life, based on long-term projections from the Reference Projections energy and emissions, update for 2012 (Verdonk and Wetzels, 2012) is assumed to be 16 €ct/kWh in case of a demand of 50 MWh/year and 10 €ct/kWh in case of an electricity demand of more than 50 MWh/year.

5.2 Biomass prices

Biomass as a fuel comes in various quality levels. Solid biomass is based on pruning and thinning wood as a reference. Liquid biomass will be discussed in a separate section. Digestion has two references: biomass for all-feedstock digesters and biomass for manure co-digestion.

5.2.1 Solid biomass: Pruning and thinning wood

Pruning and thinning wood is the reference fuel for new installations for thermal conversion of solid biomass. This has remained unchanged compared to the advice for the SDE+ 2012. The biomass consists of fresh wood chips from forests, landscapes and gardens. The energy content of fresh wood is about 7 GJ/tonne. However, a large part of the wood delivered to the installations will originate from stock. Due to natural drying processes of the wood stock, the annual average energy content is assumed to be 9 GJ/tonne. The price range for pruning and thinning wood ranges from 38 to 58 €/tonne. The reference price is assumed to be 48 €/tonne or 5.3 €/GJ. Particularly due the interactions near the border with Germany and Belgium, it may be impossible to obtain pruning and thinning wood for this price throughout the Netherlands. Because pruning and thinning wood mainly have a local market, the same risk surcharge applies that was established earlier for cut wood and pruning wood (Lensink et al., 2010). The category of pruning and thinning wood is assumed to have a risk surcharge of 1 €/tonne.

The opportunities for running new projects on B quality wood and their consequences for the wood market have not yielded an unequivocal signal from the market consultation. In previous years (until 2010) B quality wood was the reference fuel for thermal conversion of biomass. As a result of the calculated switch from B quality wood to a new reference fuel, the base rate has risen compared to the base rates of 2010. Allowing installations that run on B quality wood in categories[3] for which ECN and DNV KEMA have used a different reference fuel will primarily lead to over-subsidising of these installations.

5.2.2 Liquid biomass

The price of vegetable oils is still showing an upward trend. The price movements of these oils can be considered leading for the price movements of the reference fuel animal fat. The average price for 2013 is expected to be around 656 € per tonne at a net heating value of 39 GJ/tonne. The prices of animal fats are moving in line with the prices of vegetable oils. Moreover, there is a well-developed international market for vegetable oils. By trading on the international market for vegetable oils, the risks of rising prices of animal fats can be successfully hedged.

5.2.3 Digestion: Biomass for all-feedstock digesters

In the category all-feedstock digestion an installation is considered that uses waste flows from the food and beverage industry or from biofuel production. The reference fuel is assumed to consist of waste products from the food and beverage industry, where the price level is determined by the markets for feed. The reference price for SDE+ 2013 is assumed to be similar to the price of SDE+ 2012 at 25 €/tonne and a biogas production of 3.4 GJ/tonne.

An upward trend can be observed for the prices of wet animal feed. However, initiators usually own flows and are therefore less vulnerable to price fluctuations.

[3] These categories are: thermal conversion of biomass (<10 MW en >10 MW), biomass gasification and boilers fired by solid biomass.

5.2.4 Digestion: Biomass for manure co-digesters

Feedstocks for manure co-digestion: manure

The price of slurry shows regional differences, varying from 0 to -5 € per tonne in areas with manure shortage up to a maximum of -15 to -20 € per tonne in manure surplus areas. The reference price is assumed to be -15 € per tonne for a company's own manure. Due to additional transportation costs, the reference price for external supply is assumed to be -10 €/tonne.

About 90% of the total input remains as digestate. On average, the removal of digestate requires an additional 15 € per tonne.

Feedstocks for manure co-digestion: co-substrate

The so-called positive list of co-products is expanded with 80 new products in 2012. The majority of these products is currently exported to digesters abroad. By allowing these co-products, a better linkage is made to regulations for foreign digesters. However, there is a limitation to the concentrations of heavy metals and organic impurities. This new expansion will slightly lower the pressure on the market for co-products, allowing the cost-efficiency of the biogas revenue of the installations to be kept up to level. Year after year there are fluctuations in the market prices of maize. Figure 1 illustrates the price fluctuations.

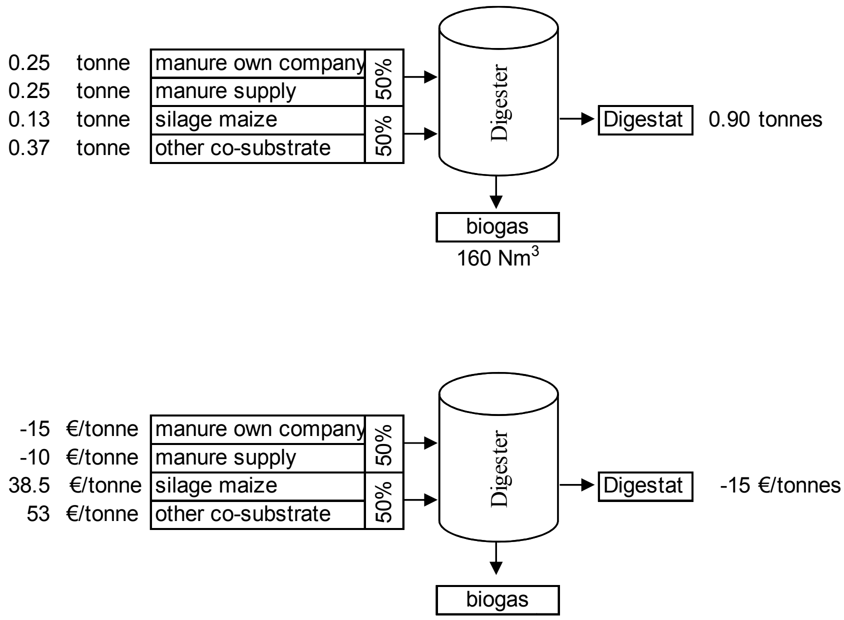
Figure 1: Indexed maize prices 1996-2012 based on LEI prices, index = 100 for the second quarter of 2010

To prevent the annual fluctuations from having too large an impact on the calculated base rates, the market consultation of 2010 yielded the insight that a long-term average is a more desirable starting point. To correct for fluctuations, the average of the last five years has been calculated based on trade information of the LEI (corrected for transport). The average maize price in the period January 2007 up to June 2012 amounts to 38.5 €/tonne.

As the high maize prices of recent years have led to increasing deployment of other agricultural residual products to lower the average price of co-substrate and increase the average gas yield, the share of maize has in some cases been reduced to less than 30% of the co-substrate, with the other 70% being filled by energy mixes, crop residue and glycerine. Moreover, glycerine, with its currently high price, will partly be replaced by new co-products that were exported up to recently.

Figure 2 shows a schematic overview of the assumed feedstock flows in the co-digester.

Figure 2: Flows and prices for digestion inputs and outputs[4]



Next to maize, other energy-rich co-substrates will be utilised. The reference gas yield of other co-substrates is assumed to be 330 Nm^3/tonne. In view of the price developments of energy-rich co-substrates, the average price of co-substrate (excluding maize) in 2012 was indexed with 2% to 7.65 €/GJ or 53 €/tonne at the start of the project, with a net gas yield of 6.9 GJ/tonne. The gas yield of the total input, i.e. manure and co-substrate, amounts to 3.4 GJ/tonne. In view of price developments during the project, all cost items will be indexed with 2%/year for inflation. This also applies to feedstock costs. Table 5 offers an overview of the used prices for reference fuels.

4 The selected calculation method is the method that is common for the market, i.e. expressing the energy content of manure input and co-substrates as gas yield in Nm^3/tonne or GJ/tonne at a certain energy content of the gas (21 MJ/m^3). The calculation is based on the energy content of feedstocks in GJ of gas yield per tonne of input. For the sake of completeness: tonnes of input are based on the entire product, not on the dry matter content alone.

Table 5: Used biomass prices for installations applying for SDE+ in 2013

	Energy content	Price (range)	Reference price
	[GJ/tonne]	[€/tonne]	[€/GJ]
Liquid biomass			
Animal fat	39	656 (600-700)	16.8
Solid biomass			
Pruning and thinning wood	9	48 (38-58)	5.3
Digestion			
All-feedstock digestion input	3.4	25	7.4
Supply of animal manure	*0.63*	*-10 (-20 to 0)*	*-16*
Removal of animal manure	*0.63*	*-15 (-30 to -5)*	*-24*
Maize	*3.8*	*38.5 (25-45)*	*10.1*
Other co-substrate	*6.9*	*53 (23 to 200)*	*7.65*
Co-digestion input	3.4	32 (14-32)	9.4

* The energy content of digestion input is given in GJ_{biogas}/tonne. The reference price for digestion input is given in €/GJ_{biogas}.

6

Technical-economic parameters

In the next sections, the underlying parameters to arrive at the base rates will be addressed per technique. For the sake of readability, the resulting production costs of crude biogas in hub applications will also be shown. Crude biogas, contrary to green gas, does not meet the specifications required to be fed into the natural gas grid. The discussed techniques are digestion of biomass, thermal conversion of biomass, boiler fired with solid biomass, boiler fired with liquid biomass, existing installations, hydropower, wind energy, deep geothermal, solar thermal and indicative calculations for more expensive options.

6.1 Biomass digestion

6.1.1 Biogas hubs

Introduction
Crude biogas, consisting mainly of methane and carbon dioxide that is produced by different digestion plants, can be transported to a central point through a low pressure pipe. At the so-called hubs, biogas is deployed for the production of electricity or heat. Biogas can also be upgraded into green gas.

A production system for crude biogas consists of the following components:

- Digester.
- Limited gas scrubbing: this step consists mainly of ammonia removal and a deeper hydrogen sulphide-removal than in direct on-site use of the biogas in a CHP installation.
- Heat for the digester: part of the biomass will be used in a boiler to supply the required heat to the digester; it needs electricity from the grid.

- Gas drying: the biogas must be dehydrated prior to transport through crude biogas pipes.
- Transport to external application: the biogas, consisting mainly of methane and carbon dioxide, is supplied to a different installation where it will be deployed as replacement of natural gas.

Reference systems for production of crude biogas

The main assumptions in establishing the technical-economic parameters for the production of crude biogas are:

- The cost of CO_2 separation is not included in the calculation[5].
- The cost of hydrogen sulphide or ammonia removal are discounted in the cost of the digester. Moreover, extra costs are included for additional gas cleaning, gas drying, extra investment for better gas measuring than in CHP applications and a compressor to pump crude biogas to the required pipeline pressure.
- Combustion of part of the crude biogas in a boiler delivers the heat for the digester.
- The electricity for the installation is purchased.

The costs of green gas production include extra costs for additional gas cleaning, gas dehydration, extra investment for better gas measuring than in CHP applications and a compressor to pump crude biogas to the required pipeline pressure.

Bio-gas pipe

A biogas pipe is needed to transport the crude biogas from the digester to the central hub. The cost of a bio-gas pipe with an estimated length of 10 km and a diameter of 110 mm amounts to approximately 75,000 €/km. Compared to the draft advice, this is an increase of 15,000 €/km due to additional costs for infrastructure crossings, for example.

Description of reference CHP hub

The technical-economic parameters for the reference CHP hub, including biogas pipe, are indicated in Table 6. These parameters result in a cost price of a CHP hub of 5.6 €/GJ. The biogas is converted into heat and power with an annual efficiency of 61% for end use.

[5] The reference installation complies with the emission standards. The cost of CO_2 separation are not included in the framework of this study, because these costs need not necessarily be made for the production of green gas.

Table 6: Technical-economic parameters CHP hub

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	12.7
Electric capacity	[MW_e]	4.7
Thermal output capacity	[MW_{th_output}]	6.1
Full-load hours electricity supply	[h/a]	8000
Full load hours heat supply	[h/a]	4000
Maximum electrical efficiency	[%]	37
Electricity loss in heat supply		n.a.
Investment cost	[€/kW_{th_input}]	445
Fixed O&M costs	[€/kW_{th_input}]	37
Variable O&M costs (electricity)	[€/kWh_e]	0
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	n.a.
Fuel price	[€/tonne]	0
Fuel surcharge	[€/tonne]	0
Production costs	[€/GJ]	5.6

Description of reference heat hub

The technical-economic parameters for the reference heat hub, including biogas pipe, are indicated in Table 7. These parameters result in a cost price of a heat hub of 1.0 €/GJ. The biogas is converted into heat with an annual efficiency of 90% for end use.

Table 7: Technical-economic parameters heat hub

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	12.7
Full load hours heat supply	[h/a]	7000
Internal electricity demand	[kWh/GJ_{output}]	0.80
Electricity rate	[€/kWh]	0.10
Investment cost	[€/kW_{th_output}]	120
Fixed O&M costs	[€/kW_{th_output}]	1.7
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	n.a.
Fuel price	[€/tonne]	0
Fuel surcharge	[€/tonne]	0
Production costs	[€/GJ]	1.0

Description of reference green gas hub

The reference system for a green gas hub has a crude biogas input of 2200 Nm^3/h (or 1300 Nm^3/h of green gas) using gas scrubbing by means of chemicals as gas cleaning technique. The heat that is required for this technique is generated by firing part of the crude biogas in a boiler. The needed electricity is purchased.

It is assumed that the produced green gas is fed into the national high pressure grid of 40 bar. As the selected reference purification technique (gas scrubbing with chemicals) operates under atmospheric pressure, the produced green gas needs to be compressed to 40 bar.

The technical-economic parameters for the reference green gas hub, including biogas pipe and green gas compression up to 40 bar, are indicated in Table 8. These parameters lead to a cost price of a green gas hub amounting to 16.0 €ct/Nm^3. The biogas is converted into green gas at an annual average efficiency of almost 90%.

Table 8: Technical-economic parameters green gas hub

Parameter	Unit	Advice 2013
Reference size	[Nm^3_{biogas}/h]	2200
Full load hours	[h/a]	8000
Internal heat demand	[% biogas]	10
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.23
Electricity rate	[€/kWh]	0.10
Energy content substrate	[GJ_{biogas}/tonne]	n.a.
Feedstock costs	[€/tonne]	0
Feedstock price surcharge	[€/tonne]	0
Investment cost	[€ per Nm^3_{biogas}/h]	2270
Fixed O&M costs	[€/a per Nm^3_{biogas}/h]	190
Efficiency gas cleaning	[% methane]	99.9
Production costs	[€ct/Nm^3]	16.0

It is also possible to feed into a medium pressure grid of a regional distribution grid with a maximum pressure of 8 bars. Combined with gas scrubbing, an extra compressor will need to be installed here, too. Contrary to gas scrubbing with chemicals, cryogenic purification technology functions at a pressure of about 8 bars, allowing the gas to be directly fed into the regional medium pressure grid. Moreover, this technology also has the potential benefit of releasing a flow of pure CO_2, which may be commercially tradable. A disadvantage is that this technology is still relatively new; there are no existing plants with gas grid feed-in that have already proven themselves for a number of years. Cryogenic purification is not considered a reference technique, although some experience has been gained in a number of independent installations.

6.1.2 WWTP

On request of the Ministry of EL&I, ECN and DNV KEMA paid particular attention to the various technical options in waste water treatment plants. To be more precise, two topics have been examined: production of renewable energy when replacing an existing gas engine, and expansion of the capacity by means of thermal pressure hydrolysis. Regarding the replacement of the gas engine, it is assumed that this will be done at the location itself: replacing the installation's own CHP by linking to a CHP hub is less obvious due to the high electricity use of the installation. An independent installation that fully converts waste water treatment gas into heat is profitable; for comparison check the calculation of linkage to a heat hub. That is why the categories for heat and CHP hubs for WWTPs are not calculated.

Production of green gas after replacing gas engine

The reference system for this category has a crude biogas production of 100 Nm^3/h (or 60 Nm^3/h green gas). This is comparable to a CHP capacity of 200 kW_e. Gas scrubbing is the reference technology for gas cleaning in waste water treatment plants. The heat that is required for this technique is generated by firing part of the crude biogas in a boiler. The residual heat that is released in this process can be used for covering part of the heat demand of the digester. The needed electricity is purchased. Table 9 shows the technical-economic parameters for the production of crude biogas and green gas.

Table 9: Technical-economical parameters for WWTP (green gas)

Parameter	Unit	Advice 2013
Reference size	[Nm^3_{biogas}/h]	100
Full load hours	[h/a]	8000
Internal heat demand	[% biogas]	15
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.15
Electricity rate	[€/kWh]	0.10
Investment cost (digester)	[€ per Nm^3_{biogas}/h]	-
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	-
Energy content substrate	[GJ_{biogas}/tonne]	22
Feedstock costs	[€/tonne]	-
Feedstock price surcharge	[€/tonne]	-
Investment costs (gas upgrading)	[€ per Nm^3_{biogas}/h]	7515
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	506
Efficiency gas cleaning	[% methane]	99.9

Production of renewable energy after replacing gas engine

The reference system for the production of crude biogas and CHP has a thermal input of 570 kW_{th}. This results in an electric capacity of 200 kW_e for CHP. Tables 10 and 11 show the technical-economic parameters of WWTP for crude biogas and CHP respectively.

Table 10: Technical-economical parameters for WWTP (crude biogas). The column 'other' refers to the linkage to a CHP or green gas hub.

Parameter	Unit	Advice 2013 (heat)	Advice 2013 (other)
Reference size	[Nm^3_{biogas}/h]	100	100
Full load hours	[h/a]	7000	8000
Internal heat demand	[% biogas]	10	10
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.02	0.02
Electricity rate	[€/kWh]	0.16	0.16
Investment cost (digester)	[€ per Nm^3_{biogas}/h]	-	-
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	-	-
Energy content substrate	[GJ_{biogas}/tonne]	22.0	22.0
Feedstock costs	[€/tonne]	-	-
Feedstock price surcharge	[€/tonne]	-	-
Investment cost (limited gas cleaning/gas drying)	[€ per Nm^3_{biogas}/h]	823	823
Fixed O&M costs (limited gas cleaning/gas drying)	[€/a per Nm^3_{biogas}/h]	59	59
Efficiency gas cleaning	[% methane]	-	-
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	4.1 / 1.3	3.7 / 1.2
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	2.4	
Base rate though green gas hub (16.0 €ct/Nm_3 hub and 89.9% efficiency)	[€ct/Nm^3]		20.1

Table 11: Technical-economical parameters for WWTP (CHP)

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	0.571
Electric capacity	[MW_e]	0.200
Thermal output capacity	[MW_{th_output}]	0.257
Full-load hours electricity supply	[h/a]	8000
Full load hours heat supply	[h/a]	4000
Maximum electrical efficiency	[%]	35
Electricity loss in heat supply		-
Investment cost	[€/kW_{th_input}]	455
Fixed O&M costs	[€/kW_{th_input}]	37
Variable O&M costs (electricity)	[€/kWh_e]	0
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	22
Fuel price	[€/tonne]	-
Fuel surcharge	[€/tonne]	-

Increasing the sludge digestion capacity in existing WWTPs by means of thermal pressure hydrolysis
The biogas production from waste water treatment plants can be increased by expanding the existing purification installation with thermal pressure hydrolysis. It is assumed that the existing purification installation is already equipped with a CHP gas engine.

Waste water treatment plants digest sewage sludge. In most cases the gas yield is used to generate electricity with a CHP gas engine. This covers part of the waste water treatment installation's internal energy use. A new development in WWTPs is the expansion of these digestion installations with dehydration and pyrolysis based on thermal pressure. This way, a higher gas yield per tonne of sludge is realised. Due to the upstream dehydration, the sludge processing capacity of the existing installation will also increase, thus realising a higher gas yield for the existing installation. An additional benefit is that the sludge digestate, which arises from digestion of sludge that is pre-treated with thermal high-pressure hydrolysis, can be further dehydrated, thus lowering the transportation cost.

The reference installation of the expansion of the pre-treatment of a WWTP only includes the investment cost in the thermal pressure hydrolysis stage. The costs of dehydration and modification of the existing digestion tank are assumed to be compensated by the lower transportation cost of sludge removal.

The additional gas yield arising from an upstream thermal pressure hydrolysis stage can be deployed in various ways:

- Electricity production (more generation for installation's internal use, fully using the heat from the CHP for thermal pressure hydrolysis).
- Upgrading biogas to green gas quality.
- Crude biogas supply for external applications.

Hydrolysis has its own heat demand. This heat demand can be supplied by CHP based on the total gas yield of the digester (about 360 Nm^3/hr crude biogas). In the case of crude biogas supply or green gas supply, more gas is needed to heat the hydrolysis than supplied by the additional yield of the hydrolysis. Therefore, ECN and KEMA conclude that only a CHP option can be useful here, with a CHP of about 720 kW_e supplying the required heat. As all heat is used for the internal process, renewable electricity is the only product that is supplied, and hence eligible for an SDE+ allowance.

The technical-economic parameters for electricity production are provided in Table 12.

Table 12: Technical-economic parameters WWTP (electricity from CHP with thermal pressure hydrolysis)

Parameter	Unit	Advice 2013
Throughput of sludge	[tonne of dry matter/year]	16000
Full load hours	[hour/year]	8000
Gas yield	[Nm^3/tonne]	170
Gas yield	[Nm^3/hour]	340
Calorific value of biogas	[MJ/Nm^3]	25
CHP capacity (nett)	[kW_e]	723
Benefit of final processing	[€/tonne of dry matter input]	40
Total investment	[€/kW_e]	6100
Total variable costs	[€/kW_e]	800

6.1.3 Manure mono-digestion

The Netherlands has a large manure stock. Next to co-digestion of manure for the production of green gas, renewable heat and CHP applications, manure can also be digested without using co-substrate. This application, called manure mono-digestion, meets the criteria of deployment of at least 50% manure and is therefore eligible for the category manure co-digestion. This year, the Ministry of EL&I asked ECN and DNV KEMA to deliver separate advice on the production costs for manure mono-digestion.

Description of reference installation for production of crude biogas and green gas
The reference system for this category has a crude biogas production of 24,5 Nm^3/h (or 14 Nm^3/h green gas). That is comparable to a CHP capacity of 48 kW_e, which makes the reference consistent with the reference in the advice for renewable electricity for this category.

The reference gas cleaning technique is based on a configuration of membranes. The heat that is needed to heat the digester is generated by firing part of the crude biogas in the boiler. The required electricity is obtained from the grid.

Tables 13 and 14 show an overview of the technical-economic parameters for the production of crude biogas and green gas respectively.

Table 13: Technical-economical parameters for manure mono-digestion (crude biogas)

Parameter	Unit	Advice 2013 (heat)	Advice 2013 (other)
Reference size	[Nm^3_{biogas}/h]	24.5	24.5
Full load hours	[h/a]	7000	8000
Internal heat demand	[% biogas]	15	15
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.10	0.10
Electricity rate	[€/kWh]	0.16	0.16
Investment cost (digester)	[€ per Nm^3_{biogas}/h]	12450	12450
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	675	675
Energy content substrate	[GJ_{biogas}/tonne]	0.77	0.77
Feedstock costs	[€/tonne]	-	-
Feedstock price surcharge	[€/tonne]	-	-
Investment cost	[€ per Nm^3_{biogas}/h]	1175	1175
Fixed O&M costs	[€/a per Nm^3_{biogas}/h]	118	118
Efficiency gas cleaning	[% methane]	-	-
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	69.0 / 21.8	60.7 / 19.2
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	25.2	
Base rate through CHP hub (5.6 €/GJ hub and 61% efficiency)	[€/GJ]		37.1
Base rate though green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		83.6

Table 14: Technical-economical parameters for manure mono-digestion (green gas)

Parameter	Unit	Advice 2013
Reference size	[Nm^3_{biogas}/h]	24.5
Full load hours	[h/a]	8000
Internal heat demand	[% biogas]	15
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.41
Electricity rate	[€/kWh]	0.10
Investment cost (digester)	[€ per Nm^3_{biogas}/h]	12450
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	675
Energy content substrate	[GJ_{biogas}/tonne]	0.77
Feedstock costs	[€/tonne]	-
Feedstock price surcharge	[€/tonne]	-
Investment costs (gas upgrading)	[€ per Nm^3_{biogas}/h]	6950
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	380
Efficiency gas cleaning	[% methane]	99.0

Description of reference installation for renewable heat and electricity

The reference installation for the production of renewable heat and electricity is based on the manure produced by the company itself. Based on the energy content of manure and the electrical efficiency of the gas engine, the reference installation delivers a net electrical output of 48 kW_e. Technically, electricity involves a CHP installation in which the 31 kW_{th} of heat is entirely deployed for the internal digestion process. This leaves only electricity to supply and to allocate SDE+ allowance to.

Tables 15 and 16 show the technical-economic parameters of manure mono-digestion for heat and electricity, respectively.

Table 15: Technical economical parameters for manure mono-digestion (heat)

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	0.149
Full load hours heat supply	[h/a]	7000
Internal heat demand	[% biogas]	15
Internal electricity demand	[kWh/GJ_{output}]	5.41
Electricity rate	[€/kWh]	0.16
Investment cost	[$€/kW_{th\_output}$]	2755
Fixed O&M costs	[$€/kW_{th\_output}$]	154
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	0.77
Fuel price	[€/tonne]	-
Fuel surcharge	[€/tonne]	-

Table 16: Technical economical parameters for manure mono-digestion (electricity)

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	0.149
Electric capacity	[MW_e]	0.048
Thermal output capacity	[MW_{th_output}]	0.031
Full-load hours electricity supply	[h/a]	8000
Full load hours heat supply	[h/a]	0
Maximum electrical efficiency	[%]	32.0
Electricity loss in heat supply		-
Investment cost	[$€/kW_{th\_input}$]	2785
Fixed O&M costs	[$€/kW_{th\_input}$]	200
Variable O&M costs (electricity)	[$€/kWh_e$]	0
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	0.77
Fuel price	[€/tonne]	-
Fuel surcharge	[€/tonne]	-

6.1.4 Manure co-digestion

In co-digestion of manure for the production of green gas, renewable heat and CHP applications, next to manure no more than 50% of co-substrate is used as input for the digester.

Description of reference installation for production of crude biogas and green gas

Based on the scale-size of new initiatives, the production capacity of new installations has been projected at 505 Nm^3/h of crude biogas (or 315 Nm^3/h green gas). The size of the digester of an installation of this scale is comparable to a digester of a bio-CHP installation of 1.1 MW_e. Scale effects appear to be limited for digesters. The maximum size of a digester tank is limited because the material must be homogenised; the diameter of the roof of a digester is also bound to a maximum value. Therefore several tanks are often placed next to each other.

The reference gas cleaning technique is gas scrubbing. The heat that is needed for this technique is generated by firing part of the crude biogas in a boiler. The residual heat released during gas scrubbing is sufficient to heat the digester. The needed electricity is purchased.

Additional comments

It is assumed that the produced green gas can be fed into the local 8-bar grid. Tables 17 and 18 show an overview of the technical-economic parameters for the production of crude biogas and green gas respectively.

Table 17: Technical-economic parameters manure co-digestion (crude biogas)

Parameter	Unit	Advice 2013 (heat)	Advice 2013 (other)
Reference size	[Nm^3_{biogas}/h]	505	505
Full load hours	[h/a]	7000	8000
Internal heat demand	[% biogas]	5	5
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.12	0.12
Electricity rate	[€/kWh]	0.10	0.10
Investment cost (digester)	[€ per Nm^3_{biogas}/h]	4500	4500
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	280	280
Energy content substrate	[GJ_{biogas}/tonne]	3.4	3.4
Feedstock costs	[€/tonne]	32	32
Feedstock price surcharge	[€/tonne]	0.5	0.5
Investment cost	[€ per Nm^3_{biogas}/h]	350	350
Fixed O&M costs	[€/a per Nm^3_{biogas}/h]	35	35
Efficiency gas cleaning	[% methane]	-	-
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	59.4 / 18.8	56.5 / 17.9
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	21.9	
Base rate through CHP hub (5.6 €/GJ hub and 61% efficiency)	[€/GJ]		34.9
Base rate though green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		78.9

Table 18: Technical-economic parameters manure co-digestion (green gas)

Parameter	Unit	Advice 2013
Reference size	[Nm^3_{biogas}/h]	505
Full load hours	[h/a]	8000
Internal heat demand	[% biogas]	10
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.25
Electricity rate	[€/kWh]	0.10
Investment cost (digester)	[€ per Nm^3_{biogas}/h]	4500
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	280
Energy content substrate	[GJ_{biogas}/tonne]	3.4
Feedstock costs	[€/tonne]	32
Feedstock price surcharge	[€/tonne]	0.5
Investment costs (gas upgrading)	[€ per Nm^3_{biogas}/h]	3020
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	300
Efficiency gas cleaning	[% methane]	99.9

Description of reference installation for renewable heat and CHP
Manure co-digestion plants seem to be growing in size, with many new initiatives ranging from 1 to 1.5 MW and a trend towards larger projects (>1.5 MW), with manure also originating from other companies. Through the years, the composition of the co-substrate has changed, which increased the gas yield per tonne of co-substrate substantially to over 100 Nm^3/tonne of the manure and co-substrate mix. The reference installation scale is assumed to be 1.1 MW_e. An installation of this scale size will remain well below the MER limit (MER = Environmental Impact Assessment) and can be supplied with manure from two large companies. The first year will see additional costs as a result of starting up the installation. These additional costs are included in the investment costs and result in a total investment cost of 1150 €/kW_{th}.

For the renewable heat option, an investment cost of 950 €/kW_{th} for crude biogas is assumed, including the cost of an additional boiler. The boiler supplies heat/steam of about 120°C. Costs of a gas pipe or a heat grid have not been included.

Additional comments
The gas engine efficiency is calculated at a level that complies with the NO_X emission requirements from the decree on emission limits for mid-sized combustion plants (BEMS). Calculations for the SDE base rates are calculated at an electrical efficiency in the conversion of the biogas into net electricity supply amounting to 37%. The feedstock costs of manure co-digestion are volatile due to the dependence on both manure prices and co-substrate costs. Although it is impossible to close long-term contracts to cover all these price risks, there is some flexibility in the substrate mix. The feedstocks are obtained from the regional market, which limits the price surcharge to 1 € per tonne of co-substrate.

The technical-economic parameters of manure co-digestion for heat and CHP are illustrated in Table 19 and Table 20.

Table 19: Technical economical parameters for manure co-digestion (heat)

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	3.0
Full load hours heat supply	[h/a]	7000
Internal heat demand	[% biogas]	5
Internal electricity demand	[kWh/GJ_{output}]	5.41
Electricity rate	[€/kWh]	0.10
Investment cost	[$€/kW_{th\_output}$]	954
Fixed O&M costs	[$€/kW_{th\_output}$]	57
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	3.4
Fuel price	[€/tonne]	32
Fuel surcharge	[€/tonne]	0.5

Table 20: *Technical-economic parameters manure co-digestion (CHP)*

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	3.0
Electric capacity	[MW_e]	1.1
Thermal output capacity	[MW_{th_output}]	1.4
Full-load hours electricity supply	[h/a]	8000
Full load hours heat supply	[h/a]	4000
Maximum electrical efficiency	[%]	37.0
Electricity loss in heat supply		-
Investment cost	[$€/kW_{th\_input}$]	1150
Fixed O&M costs	[$€/kW_{th\_input}$]	85
Variable O&M costs (electricity)	[$€/kWh_e$]	0
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	3.4
Fuel price	[€/tonne]	32
Fuel surcharge	[€/tonne]	0.5

6.1.5 All-feedstock digestion

Description of reference installation for production of crude biogas and green gas
The reference technology for this category is a digester with various residual flows from the food and beverage industry with a production capacity of crude biogas of 950 Nm^3/h. FGV waste can also be deployed. The produced green gas is upgraded to green gas by means of gas scrubbing technology. Calculations are based on a feedstock price of 25 €/tonne. The energy content of the biogas is 3.4 GJ/tonne of substrate. Table 21 and Table 22 show the technical-economic parameters for the production of crude biogas or green gas in all-feedstock digesters.

Table 21: Technical-economical parameters for all-feedstock digestion (crude biogas)

Parameter	Unit	Advice 2013 (heat)	Advice 2013 (other)
Reference size	[Nm^3_{biogas}/h]	950	950
Full load hours	[h/a]	7000	8000
Internal heat demand	[% biogas]	5	5
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.12	0.12
Electricity rate	[€/kWh]	0.10	0.10
Investment cost (digester)	[€ per Nm^3_{biogas}/h]	3900	3900
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	220	220
Energy content substrate	[GJ_{biogas}/tonne]	3.4	3.4
Feedstock costs	[€/tonne]	25	25
Feedstock price surcharge	[€/tonne]	0	0
Investment cost	[€ per Nm^3_{biogas}/h]	275	275
Fixed O&M costs	[€/a per Nm^3_{biogas}/h]	25	25
Efficiency gas cleaning	[% methane]	-	-
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	47.6 / 15.0	45.2 / 14.3
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	17.7	
Base rate through CHP hub (5.6 €/GJ hub and 61% efficiency)	[€/GJ]		29.1
Base rate though green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		66.4

Table 22: Technical-economical parameters for all-feedstock digestion (green gas)

Parameter	Unit	Advice 2013
Reference size	[Nm^3_{biogas}/h]	950
Full load hours	[h/a]	8000
Internal heat demand	[% biogas]	10
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.25
Electricity rate	[€/kWh]	0.10
Investment cost (digester)	[€ per Nm^3_{biogas}/h]	3900
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	220
Energy content substrate	[GJ_{biogas}/tonne]	3.4
Feedstock costs	[€/tonne]	25
Feedstock price surcharge	[€/tonne]	0
Investment costs (gas upgrading)	[€ per Nm^3_{biogas}/h]	2400
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	240
Efficiency gas cleaning	[% methane]	99.9

Description of reference installation for renewable heat and CHP

In this digestion option, an existing installation is adjusted such that a heat production or electricity production installation is integrated in the existing installation. The feedstock is mainly supplied by the existing installation and the energy from the produced biogas is mostly supplied back to the same installation as electricity, biogas gas, heat or a combination of these. A typical range of the installations is 2 to 7 MW_e with a reference capacity of 3 MW_e. The feedstock prices are primarily determined by the feed market where almost all feedstocks have an alternative use. The feedstock price is projected to be 25 €/tonne. The cost of removing the digestate is transferred to the feedstock cost. The energy content of the substrate is 3.4 GJ/tonne substrate.

The technical-economic parameters of all-feedstock digestion for heat and CHP are illustrated in Table 23 and Table 24.

Table 23: Technical economical parameters for all-feedstock-digestion (heat)

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	8.1
Full load hours heat supply	[h/a]	7000
Internal heat demand	[% biogas]	5
Internal electricity demand	[kWh/GJ_{output}]	5.41
Electricity rate	[€/kWh]	0.10
Investment cost	[€/kW_{th_input}]	586
Fixed O&M costs	[€/kW_{th_input}]	32
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	3.4
Fuel price	[€/tonne]	25
Fuel surcharge	[€/tonne]	0

Table 24: Technical-economic parameters manure all-feedstock digestion (CHP)

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	8.1
Electrical capacity	[MW_e]	3.0
Thermal output capacity	[MW_{th_output}]	3.9
Full-load hours electricity supply	[h/a]	8000
Full load hours heat supply	[h/a]	4000
Maximum electrical efficiency	[%]	37
Electricity loss in heat supply		-
Investment cost	[€/kW_{th_input}]	1055
Fixed O&M costs	[€/kW_{th_input}]	78
Variable O&M costs (electricity)	[€/kWh_e]	0
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	3.4
Fuel price	[€/tonne]	25
Fuel surcharge	[€/tonne]	0

6.2 Thermal conversion

In thermal conversion of biomass, excluding gasification for green gas production as discussed in Section 6.11.2, two system sizes are distinguished, with a boundary value of 10 MW_e.

Thermal conversion < 10 MW_e

Many initiatives up to 10 MW_e are developed for locally available biomass flows. Local authorities often play an initiating or facilitating role. Installations up to 10 MW_e must meet BEMS requirements, resulting in additional measures having to be taken to reduce the emission of nitric oxides, for example by means of a DeNOx installation. The investment cost amounts to 1550 €/kW_{th}. These costs are higher compared to the draft advice, which is due to the fact that the market consultation has made it clear that licensing authorities often do not allow open storage of biomass. The additional investment of a DeNOx installation is projected at 45 /kW_e for small installations. Using a reduction substance such as urea translates into higher O&M costs, which are projected at 0.006 €/kWh.

Thermal conversion of biomass (> 10 MW_e)

The reference is a wood-fired installation with an input capacity of about 67 MW_{th}. Last year's advice was based on a tapped condensing turbine for heat supply. The boiler has a thermal capacity of about 70 MW_{th} and can supply heat at a temperature of 100 to 120ºC to a district heating grid through low pressure steam extraction by means of a back pressure turbine. The starting point is that the back pressure turbine is able to supply 50 MW_{th}.

The starting point of the reference installation is that it is linked to a large existing district heating grid, allowing for optimal deployment of the produced heat. The number of full load hours of heat supply is therefore high at 7500 hours. At times when there is no need for full load heat supply, the entire installation will need to operate in partial load. Such an installation is usually located in an industrial area, preferably near existing conventional CHP plants and good supply route for biomass.

The reference installation is based on pruning and thinning wood as fuel. This type of wood allows for deployment of higher steam parameters, thus enabling a higher electrical efficiency. Due to the lower energy content, a larger storage and transport system is needed as well as a larger incineration component for the installation. The flue gas cleaning can be downgraded given that fresh wood contains significantly less harmful components than B-quality wood.

The technical-economic data of these reference installations have been summarised in Table 25.

Table 25: Technical-economic parameters of thermal conversion of biomass

Parameter	Unit	Advice 2013 (small, <10 MW_e)	Advice 2013, (large, >10 MW_e)
Input capacity	[MW_{th_input}]	8.7	67
Electrical capacity	[MW_e]	1.65	9.5
Thermal output capacity	[MW_{th_output}]	5.0	50
Full-load hours electricity supply	[h/a]	8000	7500
Full load hours heat supply	[h/a]	4000	7500
Maximum electrical efficiency	[%]	19	14
Electricity loss in heat supply		1:4	-
Investment cost	[€/kW_{th_input}]	1550	1840
Fixed O&M costs	[€/kW_{th_input}]	80	110
Variable O&M costs (electricity)	[€/kWh_e]	0.006	0
Variable O&M costs (heat)	[€/GJ]	0	0
Energy content fuel	[GJ/tonne]	9	9
Fuel price	[€/tonne]	48	48
Fuel surcharge	[€/tonne]	1	1

6.3 Boiler fired by solid biomass

The reference installation for this category is a hot water boiler with a combustion grate, using wood from pruning and thinning as reference fuel. The average scale size of new installations involves a biomass capacity of 4 MW_{th}. The reference installation has a heat supply capacity of 10 MW_{th}, which, despite the deviation from the average scale size, has a cost level that is representative for installations in the range of 1 to 15 MW_{th}. In the reference installation, the boiler is placed in an existing boiler room in the industry, in horticulture or in a district heating installation. The cost of the distribution system of a heat grid has not been included. Civil works are included in the investment costs. The fixed O&M costs and the investment costs do include a cost item for flue gas cleaning, including a DeNOx. Based on the responses received during the consultation, the investment cost has been raised from 370 €/kW_{th} to 425 €/kW_{th} on output basis. The high investment costs are particularly caused by the higher costs of biomass storage and flue gas cleaning. The heat is partly used by industry and partly for space heating. Table 26 provides an overview of the technical-economic parameters.

Table 26: Technical-economic parameters of hot-water boiler fired by solid biomass

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	11.1
Thermal output capacity	[MW_{th_0utput}]	10
Full load hours heat supply	[h/a]	7000
Investment cost	[€/kW_{th_output}]	425
Fixed O&M costs	[€/kW_{th_output}]	62
Variable O&M costs (heat)	[€/GJ]	-
Energy content fuel	[GJ/tonne]	9
Fuel price	[€/tonne]	45
Fuel surcharge	[€/tonne]	1

6.4 Boiler fired by liquid biomass

In some cases, gas boilers can easily and quickly be replaced by boilers fired by liquid biomass, such as for example pyrolysis oil. The selected reference fuel is animal fat. Given the relatively small contribution of the investment costs to the base rate and the option for initiators to further reduce these investment costs by installing adjusted burners in existing boilers, the investment amount has been set at zero in this advice. This makes the calculation representative for the deployment of liquid biomass in new bio-boilers as well as for the deployment of liquid biomass in adjusted, existing boilers. Table 27 shows the parameters for a boiler fired by liquid biomass.

Table 27: Technical-economic parameters new and existing boilers fired by liquid biomass

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	11.1
Thermal output capacity	[MW_{th_0utput}]	10
Full load hours heat supply	[h/a]	7000
Investment cost	[€/kW_{th_output}]	0
Fixed O&M costs	[€/kW_{th_output}]	24
Variable O&M costs (heat)	[€/GJ]	-
Energy content fuel	[GJ/tonne]	39
Fuel price	[€/tonne]	656
Fuel surcharge	[€/tonne]	0

6.5 Existing installations

6.5.1 Heat utilisation in existing projects

Existing renewable energy projects often have options for additional heat supply. This heat utilisation is usually not profitable without additional support. ECN and KEMA calculate the cost price of renewable heat supply for such projects. The payment in the SDE+ scheme is corrected for the market price of heat. The objective is to make heat demand more sustainable. Utilisation of latent heat demand need not immediately become appealing.

There is a large diversity of existing renewable energy projects. One base rate for heat utilisation in all these installations will probably lead to overstimulation of the lower cost heat projects or poor effectiveness of the scheme, with many relatively expensive projects unable to become profitable. That is why ECN and DNV KEMA, similar to 2012, advise to use different categories to realise an effective and efficient support of heat utilisation in existing projects.

ECN and DNV KEMA expect that a significant potential of renewable heat can be usefully deployed in large incineration plants, particularly waste incineration plants, in relatively small agricultural digesters, manure co-digestion plants and large industrial digesters. On request of market parties and after consultation with EL&I, ECN and DNV KEMA also calculated the option of heat deployment in composting installations.

Expanding heat supply in large incineration and digestion installations
The cost structure of heat supply in large projects partly depends on the primary process of incineration or digestion. This distinction is sufficiently visible in the cost structure, given the distribution of the costs across various projects. Therefore, ECN and DNV KEMA use one reference project for the expansion of heat supply in large incineration and digestion plants. The reference installation, based on the available potential, is based on heat supply in existing waste incineration plants. Useful deployment of the heat that is released by existing waste incinerators is representative for heat supply from most of the existing processes.

Increasing the efficiency of a waste incineration installation through heat supply is a recent trend. Various waste incineration plants have already realised heat and steam supply or are in advanced stages of realising this supply. Both the MEP scheme and the SDE scheme encouraged the increasing of the efficiency. Therefore, this advice only has bearing on existing waste incineration plants that are not yet subsidised by MEP or SDE and that do not yet supply heat.

Additional heat supply from waste incineration plants involves additional costs, for example for the heat exchangers. The cost of distributing heat or steam is not included in the calculation of the unprofitable gap of the reference installation. The reference size for heat transfer is 20 MW_{th} at a full load heat supply of 7000 hours per year. Less electricity is produced in heat supply. This is included in the variable costs at a factor of 0.25 MW_e of electricity loss in the supply of 1 MW_{th} of heat, see also Table 28.

Table 28: Technical-economic parameters heat utilisation in existing projects

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_output}]	20
Full load hours heat supply	[h/a]	7000
Electricity loss in heat supply		1:4
Investment cost	[€/kW_{th_output}]	250
Fixed O&M costs	[€/kW_{th_output}]	3
Variable O&M costs (heat)	[€/GJ]	4.3
Energy content fuel	[GJ/tonne]	0
Fuel price	[€/tonne]	0
Fuel surcharge	[€/tonne]	0

As waste incineration plants are not always representative for heat utilisation in existing projects, two different situations have been examined: expansion of heat supply in existing manure co-digestion and heat utilisation in composting.

Heat utilisation in existing agricultural digestion installations

The base rate that is to be advised on has bearing on the expansion of an existing installation. The majority of installations that are eligible are manure co-digestion installations. However, existing agricultural installations such as digesters that use maize instead of manure, have a similar cost structure. The selected reference installation is therefore an existing manure co-digestion installations at the installation's own site. Contrary to a new installation, the initiator does not have a choice in case of an existing installation. An existing digester will therefore have to limit itself to the heat demand of the immediate surroundings. The most obvious option is the latent heat demand for digestate drying at the installation's own site.

The biogas from the digestion tank is used in a gas engine for electricity generation. The starting point of the calculation is that the installation will receive a MEP allowance until mid-2017. The installation can be expanded with a second gas engine to which an SDE allowance had been allocated. It is assumed that this expansion does not affect the costs of heat utilisation.

The costs related to the supply of manure and co-substrate and the removal of digestate are covered by the MEP allowance. Additional heat utilisation does not lead to a change in these biomass flows. It is therefore assumed that the biomass costs will not affect the costs of heat utilisation.

The scale size of the current co-digestion installations varies significantly, with the smallest one having an electrical capacity of less than 50 kW_e, whereas the largest one has over 5 MW_e. A slight majority of the installations has a capacity ranging from 300 to 700 kW_e or around 1.1. MW_e. Over 80% of the (OV) MEP installations has a capacity that is equal to or larger than 350 kW_e. The calculation is therefore based on an installation with a capacity of 350 kW_e. The feasible heat utilisation in these plants is 350 kW_{th}.

The calculation of the base rate assumes 4000 full load hours of additional heat supply. The additional heat utilisation requires investments in a flue gas cooler (including civil works), heat exchangers (including installation costs), heat pipe and additional construction costs. Investment costs are projected at 240 €/kW_{th}. The O&M costs have been calculated to amount to 55 €/kW_{th}/a. The technical-economic parameters are summarised in Table 29.

Table 29: Technical-economic parameters heat utilisation in existing agricultural digesters

Parameter	Unit	Advice 2013
Capacity of heat supply	[$MW_{th\ output}$]	0.350
Full load hours heat supply	[h/a]	4000
Investment cost	[€/$kW_{th\ output}$]	240
Fixed O&M costs	[€/kWth $_{output}$/a]	55
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	3.4
Fuel price	[€/tonne]	0
Fuel surcharge	[€/tonne]	0

The calculation is based on an SDE+ duration of five years. The duration of the loan and the depreciation period have also been adjusted accordingly for the calculation of the base rate

Heat utilisation in composting

Composting processes produce compost heat. Part of this is needed to maintain the right temperature of the process. The remainder is superfluous and available for useful deployment. To this end, a heat exchanger needs to be installed in the existing air exhaust system. Other costs involve pumps and pipes for heat transport, with an assumed length of 1.5 kilometres. Following the consultation responses, the investment of supplied heat output has been increased from 338 to 450 €/kW_{th}. These and other parameters are listed in Table 30. The resulting production costs amount to 4.4 €/GJ. In 2012, the base heat rate for small systems, based on a gas-fired boiler, amounted to about 6 €/GJ. This makes heat utilisation in composting profitable in most cases.

Table 30: Technical-economic parameters of heat utilisation in composting (heat)

Parameter	Unit	Advice 2013
Installation size	[$MW_{th\ output}$]	2
Full load hours heat supply	[h/a]	7000
Investment cost	[€/$kW_{th\ output}$]	450
Fixed O&M costs	[€/$kW_{th\ output}$/a]	45
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	0
Fuel price	[€/tonne]	0
Fuel surcharge	[€/tonne]	0

6.5.2 Extended life of digestion plants

The category of extended life of digestion has bearing on digestion plants whose MEP allowance has ended. Calculations are based on a heat supply of 4000 full load hours, which equals the heat supply of new projects. In view of the assumed lifetime of 12 years, ECN and DNV KEMA made calculations of maintenance to and possibly replacement of some components. These costs have been included in the O&M costs.

Table 31: Technical-economic parameters of extended life for digestion (CHP)

Parameter	Unit	Advice 2013 All-feedstock digestion	Advice 2013 Manure co-digestion
Input capacity	[MW_{th_input}]	2.2	2.2
Electrical capacity	[MW_e]	0.8	0.8
Thermal output capacity	[MW_{th_output}]	1.0	1.0
Full-load hours electricity supply	[h/a]	8000	8000
Full load hours heat supply	[h/a]	4000	4000
Maximum electrical efficiency	[%]	37	37
Electricity loss in heat supply		-	-
Investment cost	[€/kW_{th_input}]	0	0
Fixed O&M costs	[€/kW_{th_input}]	148.5	148.5
Variable O&M costs (electricity)	[€/kWh_e]	0	0
Variable O&M costs (heat)	[€/GJ]	0	0
Energy content fuel	[GJ/tonne]	3.4	3.4
Fuel price	[€/tonne]	25	32
Fuel surcharge	[€/tonne]	0	0.5

Digestion plants can also opt for not replacing the gas engine and instead linking the installation to the green gas hub, thus producing green gas instead of electricity. Table 32 shows the technical-economic parameters of production for a green gas or heat hub based on existing all-digesters and manure co-digesters.

Table 32: Technical-economic parameters of extended life for digestion (crude biogas)

Parameter	Unit	Advice 2013 All-feedstock digestion heat	Advice 2013: All-feedstock digestion (green gas)	Advice 2013 Manure co-digestion heat	Advice 2013 Manure co-digestion (green gas)
Reference size	[$Nm^3{}_{biogas}$/h]	370	370	370	370
Full load hours	[h/a]	7000	8000	7000	8000
Internal heat demand	[% biogas]	5	5	5	5
Internal electricity demand	[kWh/$Nm^3{}_{biogas}$]	0.12	0.12	0.12	0.12
Electricity rate	[€/kWh]	0.10	0.10	0.10	0.10
Investment cost (digester)	[€ per $Nm^3{}_{biogas}$/h]	0	0	0	0
Fixed O&M costs (digester)	[€/a per $Nm^3{}_{biogas}$/h]	290	290	290	290
Energy content substrate	[GJ_{biogas}/tonne]	3.4	3.4	3.4	3.4
Feedstock costs	[€/tonne]	25	25	32	32
Feedstock price surcharge	[€/tonne]	0	0	0.5	0.5
Investment cost (limited gas cleaning/gas drying)	[€ per $Nm^3{}_{biogas}$/h]	385	385	385	385
Fixed O&M costs (limited gas cleaning/gas drying)	[€/a per $Nm^3{}_{biogas}$/h]	38	38	38	38
Efficiency gas cleaning	[% methane]	-	-	-	-
Production costs crude biogas	[€ct/Nm^3]/ [€/GJ]	37.7 / 11.9	36.6 / 11.6	45.7 / 14.5	44.6 / 14.1
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	14.2		17.1	
Base rate through green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		56.7		65.6

6.5.3 Extended life of incineration plants

The category for extended life of incineration plants has bearing on projects that were formerly covered by the MEP scheme, except for biomass co-firing projects. The technical-economic parameters of Table 33 are based on several projects whose MEP allowance will soon expire or has already expired. For the fuel price, linkage was sought to the fuel price for new projects (see Chapter 5). As for extended life, renovation costs and other investment costs are not included in the calculation. In line with the calculation, it is assumed that the installation remains in operation as long as the variable costs are lower than the revenue. Long-term contracts for fuel therefore need not necessarily be closed, hence a fuel price surcharge does not apply. A heat supply of 4000 full load hours has been used in the calculations. This is lower compared to heat supply in new projects, because existing projects cannot choose a location in the vicinity of suitable heat demand.

Table 33: Technical-economic parameters of extended life for incineration

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	85
Electrical capacity	[MW_e]	20
Thermal output capacity	[MW_{th_output}]	50
Full-load hours electricity supply	[h/a]	8000
Full load hours heat supply	[h/a]	4000
Maximum electrical efficiency	[%]	23.5
Electricity loss in heat supply		1:4
Investment cost	[€/kW_{th_input}]	0
Fixed O&M costs	[€/kW_{th_input}]	80
Variable O&M costs (electricity)	[€/kWh_e]	0
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	9
Fuel price	[€/tonne]	45
Fuel surcharge	[€/tonne]	0

6.6 Hydropower

The height of fall of the rivers in the Dutch Delta is limited. Existing constructions in rivers are suitable for creating height of fall that can be utilised in hydropower plants. In practise these usually range from 3 to 6 meters, but may be as high as 11 meters in exceptional cases. Small-scale hydropower has a reference installation with a height of fall that is less than five metres. The potential projects in the hydropower category have a wide distribution in investment costs and corresponding base rates. Therefore the base rates in this advice are based on specific projects, the realisation potential and the costs playing leading roles in selection.

The reference installation for this hydropower category has remained unaltered compared to the final advice SDE+ 2012 (Lensink *et al*. 2011). The technical-economic parameters of the reference installation for hydropower have been summarised in Tables 34.

Table 34: Technical-economic parameters hydropower with height of fall of less than 5 meters

Parameter	Unit	Advice 2013
Installation size	[MW]	0.5
Investment cost	[€/kW$_e$]	5900
Full load hours	[h/a]	7000
Fixed O&M costs	[€/kW$_e$/a]	210
Variable O&M costs	[€/kWh]	0

Hydropower in existing water management facilities

On request of the Dutch Ministry of Economic Affairs, Agriculture and Innovation, ECN and DNV KEMA examined the cost of production of renewable electricity from existing hydropower installations, in which adjustments are made to lower the mortality rate of fish near these installations.

The category of hydropower – fish-friendly renovation, a reference installation has been defined in which the existing turbines are replaced by fish-friendly turbines. It is very likely that in such a renovation (part of the) electrical infrastructure such as the generator, transformers and operation need to be adjusted as well. It is assumed that the required adjustments to the constructions (the civil works) are minor. Table 35 shows the technical-economic parameter for the category of hydropower – fish-friendly renovation.

Table 35: Technical-economic parameters of fish-friendly renovation of hydropower

Parameter	Unit	Advice 2013
Installation size	[MW]	1.0
Investment cost	[€/kW$_e$]	1600
Full load hours	[h/a]	4300
Fixed O&M costs	[€/kW$_e$/a]	80
Variable O&M costs	[€/kWh]	0

6.7 Wind energy

To implement the bills of Van der Werf (Parliamentary paper 33 000 XIII, no. 68) and Van Tongeren (Parliamentary papers 29023, no 128), the Dutch Ministry of EL&I requested advice on the implementation of the following categories for wind energy for the SDE+ 2013 scheme:

1. Wind energy at very wind-rich locations
2. Wind energy at wind-rich locations
3. Wind energy at low-wind locations.
4. Wind energy with turbines of 6 MW or higher
5. Wind energy with turbines in a lake
6. Wind energy at sea (see Section 6.11.3).

To establish the base rates for onshore wind energy, various wind turbines and corresponding investments have been used. The price of wind turbines supplied in the Netherlands shows a decrease of 5 to 10% compared to last year's price level. This is in line with international developments (NREL, 2012).

Additional costs on top of the turbine price include foundations (including piles), electrical infrastructure in the farm, grid connection, civil infrastructure, soil acquisition costs, interest during construction and the construction all risks insurance (CAR). As a result of the market consultation this value has been increased with 2 per cent point to 29% of the turbine costs.

The variable costs, consisting of warranty and maintenance contracts, are projected at about 1 €ct/kWh on top of which an inflation of 2% per year is calculated. Additional costs for soil are projected at 0.53 €ct/kWh. The fixed annual costs include 15.3 €/kW for liability insurance, machine breakage insurance, standstill insurance, cost for maintaining the grid, internal use, property tax, superficies allowance, control and soil and road maintenance.

The base rate has been established by combining these costs with the financial benefits. The returns are largely determined by the wind resources and the power curve of the wind turbine. Included is also a 10% yield loss, which is caused by lower availability, electrical losses and mechanical losses and wake losses.

The energy yield has been determined by a specific capacity curve per wind turbine and a given yearly average wind speed. For low-wind areas, an average wind speed has been assumed of 7 m/s at 100 metres axis height. Wind-rich areas are set at 7.25 m/s; very wind-rich areas at 7.5 m/s; and extremely wind-rich areas at 8.8 m/s.[6] The selected base rate, combined with the corresponding full-load hours, is sufficient for at least 25% of the wind turbine types that are available on the market and suitable for the specific locations. Cost-efficiency is thus realised by incentivising sufficient competition among market prices for turbines.

For wind turbines with a capacity that is higher than or equal to 6 MW, higher investment costs and lower maintenance costs of 0.95 €ct/kWh are taken into account due to the higher number of full load hours. The cost of the category Wind in Lake is based on variable O&M costs of 1.7 €ct/kWh. Moreover, a levy for placement in the water, amounting to 0.53 €ct/kWh has also been included.

During the market consultation, signals were received about wind projects being increasingly confronted with additional costs that ECN and DNV KEMA do not include in the calculations of the production costs. Examples include payments to local authorities not regulated by law, costs for participation of residents, costs related to a lengthy preparatory process and costs of legal procedures. The above-mentioned costs, and some incidental benefits, are not generic in nature and therefore ECN and DNV KEMA cannot consider them as costs (or benefits) that are eligible for subsidy, which is in line

[6] The terms 'extremely rich in wind', 'very rich in wind', 'rich in wind' and 'low-wind' are not defined in the research assignment. The research assignment only distinguishes categories that stand out in terms of wind speed. Thus, the definition of 'rich in wind' that ECN and DNV KEMA use in this report deviates from the definition of 'rich in wind' as used in the SDE+ advice for 2012 (Lensink and Faasen, 2012).

with the research assignment. The same is true for all preparation costs. The generic preparation costs are assumed to be recovered through the financial return on equity.

The technical-economic parameters are listed in Table 36; the resulting base rates are included in Table 37.

Table 36: Technical-economic parameters wind energy

Parameter	Unit	Advice 2013 (Extremely wind-rich)	Advice 2013 (very wind-rich)	Advice 2013 (wind-rich)	Advice 2013 (low-wind)	Advice 2013 (turbine > 6 MW)	Advice 2013 (wind in lake)
Installation size	[MW]	15	15	15	15	60	150
Investment costs	[€/kW$_e$]	1350	1350	1350	1325	1820	2500
Full load hours	[h/a]	3300	2800	2400	2200	3000	3200
Fixed O&M costs	[€/kW$_e$/a]	15.3	15.3	15.3	15.3	15.3	15.3
Variable O&M costs	[€/kWh]	0.0153	0.0163	0.0163	0.0163	0.0148	0.0223

Table 37: Base rates for onshore wind and wind in lake based on existing categories in SDE+

Category	Full load hours	Base rate
Onshore wind, extremely rich in wind	3300	7.0
Onshore wind, very rich in wind	2800	8.0
Onshore wind, rich in wind	2400	9.0
Onshore wind, low- wind	2200	9.5
Onshore wind ≥ 6 MW	3000	9.3
Wind in lake	3200	12.2

In the case of onshore wind ≥ 6 MW, 3000 full load hours corresponds to an extremely wind-rich environment. A base rate of 9.0 €ct/kWh for such turbines can be reached at 3130 full load hours. A base rate of 8.0 €ct/kWh corresponds to 3600 full load hours. An SDE+ decision of 8.0 €ct/kWh and maximisation at 3600 full load hours does not lead to overstimulation according to ECN and DNV KEMA, although 3600 full load hours is no longer realistic in view of the average Dutch wind resources. For wind in lake (and offshore wind) base rates of 11 €ct/kWh or lower are not realistic anyway.

6.8 Deep geothermal energy

Geothermal heat

The reference installation has been adjusted on the basis of recent experiences with the realisation of geothermal projects. Based on this observation and statements of the operators of the sources, both the flow rate and the COP[7] have been lowered to

[7] The Coefficient of Performance (COP) expresses the relation between the produced geothermal energy and the required pump energy. A COP value of 20 is considered realistically feasible under Dutch geological conditions.

respectively 138 m^3/h and 12.5 compared to the draft advice. The decrease of the COP is the result of a solution that is considered realistic by the operators: installing an additional pump for the injection of the formation water.

Reference installation Geothermal heat

The reference installation for geothermal heat for SDE+ 2013 is based on heat supply to one or multiple greenhouse horticulture businesses. The starting point is a geothermal source (aquifer) at 2300 metres depth. At a gradient of 30°C per km, a source temperature of about 80°C will be realised. The geothermal source consists of a doublet (a production and injection well) with a flow rate of 138 m^3/hour and a capacity of 6.2 MW_{th}. A heat deployment is assumed that equals an ΔT van 40 ^{o}C. Heat supply is based on 5500 full load hours. By combining the heat demand of multiple parties, the heat supply can possibly be increased.

The investment cost of the doublet and the above-ground installation amounts to €9.4 million, which equals €1520/kW_{th}. The drilling costs take up €6.7 million, including an increase of €1 million as a result of safety margins related to the release of hydrocarbons and their capturing. The other costs, for instance related to the above-ground installation and pump(s), but also for the guarantee scheme, amount to €2.7 million.

Contrary to the draft advice, a time period of 15 years is used for the loan and the write-downs. This links up better to the reference installation that supplies heat to greenhouse horticulture. The generally longer life of a geothermal source is included in the reference as a residual value of 35% at the end of the SDE+ allowance period of 15 years. The effect on the base rate is comparable to the lowering of the investment cost to 1420 €/kW_{th}, and as such is included in the investment cost.

The fixed O&M costs amount to 2% of the investment cost, equalling 30 €/kW_{th} per year. The variable O&M costs that follow from the required pump energy, based on a COP of 12.5 and electricity costs of 10 €ct/kWh, are 2.2 €/GJ_{heat}. The technical-economic parameters of geothermal heat are summarised in Table 38.

Compared to the final advice SDE+ 2012 (Lensink *et al*., 2011) the proposed adjustments to the technical-economic parameters for geothermal heat in the current advice lead to an increase in the base rate. This rise can be entirely ascribed to the adjustment of the maximum number of full load hours from 7000 to 5500. The maximum subsidy per project does not increase as a result of this adjustment.

Table 38: Technical-economic parameters deep geothermal (heat)

Parameter	Unit	Advice 2013
Thermal output capacity	[MW_{th_output}]	6.2
Full load hours heat supply	[h/a]	5500
Investment cost	[€/kW_{th_output}]	1420
Fixed O&M costs	[€/kW_{th_output}]	30
Variable O&M costs (heat)	[€/GJ]	2.2
Energy content fuel	[GJ/tonne]	0
Fuel price	[€/tonne]	0
Fuel surcharge	[€/tonne]	0

Geothermal CHP

The geothermal CHP installation is a variant of the reference installation in (Lako *et al*., 2011), based on a doublet and a depth of the hydro-thermal source of 4000 m. The reference installation in (Lako *et al*., 2011) is based on conservative assumptions that lead to higher costs for geothermal heat and electricity (CHP). In the selected variant two more favourable starting points were chosen, i.e.:

- Temperature 150°C instead of 130°C (35°C per km instead of 30°C per km).
- Flow rate 200 m^3/hour instead of 150 m^3/hour.

Moreover, the characterisation of the geothermal source in geothermal CHP is highly favourable and by no means an extrapolation of the characteristics of the geothermal source at lower depths as calculated for geothermal heat projects.

Changes in these parameters have been calculated by (Lako *et al*., 2011). Here changed parameters are combined into one single variant that is considered more realistic. It is assumed that the heat is supplied to a district heating grid at a temperature level of 75°C and that electricity is generated by means of an Organic Rankine Cycle (ORC). The capacity of the geothermal source is higher than in Lako *et al*. (2011): 25.6 MW_{th} instead of 15.7 MW_{th}. The net electric capacity of the ORC (Organic Rankine Cycle) is estimated at 1,9 MW_e, which corresponds to a net efficiency of over 7%. The number of full load hours for electricity is 5000 hours per year, excluding internal use. The heat capacity for district heating amounts to 10 MW_{th} which corresponds to a thermal efficiency of 39%. The number of full load hours for heat supply is 4000 hours/year.

Similar to the category for geothermal heat, it is assumed that both the loan and the write-downs have bearing on a period of 15 years. It is assumed that when the SDE+ allowance period of 15 years ends, there will be a residual value of 35%. This has been included in the investment cost, which consequently decreases from 1140 €/kW_{th_input} (source capacity) to 1100 €/kW_{th_input}. The O&M costs amount to 2% of the investment costs plus the electricity use of the pump(s). The technical-economic parameters are summarised in Table 39.

Table 39: Technical-economic parameters deep geothermal (CHP)

Parameter	Unit	Advice 2013
Input capacity	[MW_{th_input}]	25.6
Electrical capacity	[MW_e]	1.9
Thermal output capacity	[MW_{th_output}]	10
Full-load hours electricity supply	[h/a]	5000
Full load hours heat supply	[h/a]	4000
Maximum electrical efficiency	[%]	7.3
Electricity loss in heat supply		0
Investment cost	[€/kW_{th_input}]	1100
Fixed O&M costs	[€/kW_{th_input}]	45
Variable O&M costs (electricity)	[€/kWh_e]	0
Variable O&M costs (heat)	[€/GJ]	0
Energy content fuel	[GJ/tonne]	0
Fuel price	[€/tonne]	0
Fuel surcharge	[€/tonne]	0

6.9 Solar thermal

Solar-thermal applications such as hot tap water and possibly space heating (combined with central heating systems) have many different markets such as dwellings, apartment buildings, offices and agricultural businesses. The temperature level that is required is 65-80°C. The SDE+ category for solar thermal concerns installations with a collector area of at least 100 m^2. For this category, a large solar boiler installation, as used in the agricultural sector (veal raising), is taken as reference. The power density of the solar boiler installation has a value of 0.7 kWth/m^2. The total annual heat production for useful heat applications depends on the dimensioning of the collector system in relation to the heat demand. The assumed heat supply corresponds to 700 full load hours. The investment costs for the reference installation amount to 700 €/kW_{th}, the fixed O&M costs are 5 €/kW_{th} and the electricity use for the pump results in variable O&M costs of 1.6 €/GJ. The reference solar boiler installation has a collector area of 143.5 m^2 and a capacity of 100 kW_{th}. Table 40 provides an overview of the technical-economic parameters.

Table 40: Technical-economic parameters of solar thermal

Parameter	Unit	Advice 2013
Thermal output capacity	[MW_{th_output}]	0.1
Full load hours heat supply	[h/a]	700
Investment cost	[€/kW_{th_output}]	700
Fixed O&M costs	[€/kW_{th_output}]	5.0
Variable O&M costs (heat)	[€/GJ]	1.6
Energy content fuel	[GJ/tonne]	0
Fuel price	[€/tonne]	0
Fuel surcharge	[€/tonne]	0

6.10 Solar PV ≥15 kWp

The reference installation for solar PV has remained unaltered compared to SDE+ 2012: a roof-integrated system of 100 kW_p is assumed. Based on the research assignment, this advice offers an estimate of the lowest possible cost late 2014.

2011 was marked by a huge price drop for solar panels of up to 40%. The main drivers were price decreases of polysilicon and technological progress, but also to a large extent the overcapacity in production facilities. Due to recent, strong price decreases, the margins of many manufacturers are under pressure, as well as the margins of larger parties. The next years will be important and decisive for the PV sector. Businesses will need to strengthen their financial position and tap new sales markets.

Low-cost roof-integrated, turnkey systems with a capacity of about 100 kW_p in the Netherlands have a price level of about 1300 €/kW_p. Based on the historic growth curve for solar PV, a learning effect of about 19% per doubling in worldwide production of solar panels can be assumed. Applying such a learning effect and a moderate growth of the global market for PV results in an estimated investment cost for systems up to 100 kW_p of 1200 €/kWp by late 2014, corresponding to a base rate of slightly below 15.0 €ct/kWh. The technical-economic parameters are summarised in Table 41.

Table 41: Technical-economic parameters of solar PV≥ 15 kW_p

Parameter	Unit	Advice 2013
Installation size	[MW]	0.1
Investment cost	[€/kW_e]	1200
Full load hours	[h/a]	1000
Fixed O&M costs	[€/kW_e/a]	-
Variable O&M costs	[€/kWh]	0.017

6.11 Indicative calculations for high cost options

6.11.1 Introduction

In their research assignment, the Dutch Ministry of EL&I request advice with regard to a base rate for various categories. Should the initial analysis show that the base rate will be significantly higher than 15 €ct/kWh, then the advice may suffice by mentioning this, based on an indicative base rate. A detailed calculation is hence unnecessary, because ECN and DNV KEMA only need to offer insight in the admission of options to the free category of 15 €ct/kWh, without causing overstimulation. This section will only discuss all categories for which an indicative base rate has been calculated accordingly.

6.11.2 Biomass gasification

An SNG installation for green gas production through gasification has three components: gasification, gas cleaning and gas upgrading. In a gasification installation, solid biomass is converted into gaseous fuel, called syngas or fuel gas. The gas cleaning component removes impurities from the gas. In the final step the gas is upgraded to natural gas quality (SNG) after which the green gas can be fed into the natural gas grid.

The reference installation is based on a commercial installation with technology that has passed the small-scale demonstration stage. The reference installation has a size of about 12 MW_{th}, i.e. a production capacity of 790 Nm^3 SNG/hour. The installation can cater for its internal heat demand, but the purchase of electricity for internal use has been included in the calculation of the base rate. Combining a wood-gasifier and a gas upgrading installation results in a complex production installation: therefore 7500 full load hours per year are assumed. Table 42 provides an overview of the technical-economic parameters.

Table 42: Technical-economic parameters biomass gasification

Parameter		Advice 2013
Reference size	[Nm^3_{biogas}/h]	790
Full load hours	[h/a]	7500
Internal heat demand	[% biogas]	0
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.20
Electricity rate	[€/kWh]	0.10
Energy content biomass	[GJ_{biogas}/tonne]	9
Feedstock costs	[€/tonne]	48
Feedstock price surcharge	[€/tonne]	1
Investment cost	[€ per Nm^3_{biogas}/h]	31400
Fixed O&M costs	[€/a per Nm^3_{biogas}/h]	2688
Efficiency gas cleaning	[% methane]	100

6.11.3 Offshore wind

The reference installation for offshore wind is a 300 MW wind farm outside the 12 mile-zone. This way the reference installation corresponds to a large extent with the farms that have already received a permit. The cost indication is based on the cost projections that were made prior to the 950 MW tender (Lensink *et al.*, 2009). The cost of offshore wind will lower in time, but this is not expected to become significant before 2015 (Greenacre et al., 2010). This means that the production cost is expected to stay higher than 15 €ct/kWh (see Table 43).

Although the corresponding base rate is currently exceeding 15 €ct/kWh, ECN and DNV KEMA advise continued monitoring of the price level of offshore wind in the coming years. Various farms are under construction in the Netherlands and abroad and due to the strongly increasing experience in the offshore wind sector, costs may lower significantly before 2020.

Table 43: Technical-economic parameters offshore wind

Parameter		Advice 2013
Installation size	[MW]	300
Investment cost	[€/kW$_e$]	4000
Full load hours	[h/a]	4000
Fixed O&M costs	[€/kW$_e$/a]	150
Variable O&M costs	[€/kWh]	-

6.11.4 Free tidal current energy

This advice looks exclusively at *inshore* free tidal current energy; this involves projects that are realised in or near constructions such as seawalls or semi-permeable dams that use the existing tidal movement. No projects have been realised in this category after the SDE+ 2012 was published (Lensink *et al.*, 2011). The reference installation is based on a number of projects that, according to the sector, will soon become eligible for realisation and has thus remained unaltered compared to the SDE+ 2012. These are pilot projects that are deemed commercially exploitable with adequate production subsidy. The technology of free tidal current turbines is at the early stages of commercialisation. As a result the investment and O&M costs are relatively high. According to expectations, projects in the category 'Free tidal current energy' are not expected to be realisable for the maximum base rate of 15 €ct/kWh.

Initiatives in the category 'Energy from water' are diverse in technology and application. Next to inshore free tidal current energy, deployment of free tidal current turbines in rivers and channels near locks also constitute a possible application in the category of 'Energy from water'. This application, too, cannot be exploited in a profitable manner at the maximum base rate of 15 €ct/kWh. The technical-economic parameters listed in Table 44 are based on inshore free tidal current energy.

Table 44: Technical-economic parameters of free tidal current energy

Parameter	Unit	Advice 2013
Installation size	[MW]	1.5
Investment cost	[€/kW_e]	5100
Full load hours	[h/a]	2800
Fixed O&M costs	[€/kW_e/a]	155
Variable O&M costs	[€/kWh]	0

6.11.5 Osmosis

The potential difference between fresh water and salt water can be used to generate energy (electricity or labour). This type of electricity generation, which is also referred to as energy from osmosis, is analysed in (Lako *et al*., 2010). The below-mentioned costs are based on this analysis. There are two types of energy from osmosis that are in the R&D stage:

- Pressure-Retarded Osmosis (PRO)
- Reverse ElectroDialysis (RED)

The higher the salinity gradient is, the more efficiently the installation will operate. At the same time it is also important that the sea water and the fresh water are as clean as possible. A special feature of osmosis is that the installation can be operated for a high number of hours per year. The number of full load hours can even be as high as 8000 hours. A high capacity factor is only feasible in the commercial stage.

The reference installation is an osmosis installation of 1 MW_e. ECN and DNV KEMA estimate that the investment cost of an installation of 10 MW_e will amount to €7110/kW_e in 2020. However, from a technical and economic viewpoint, it is not feasible to realise an installation of more than 1 MW_e right now, because the development of the technology is progressing step by step. When calculating with a scale factor that equals a capacity coefficient of 0.8 to 0.9, the investment cost will increase to €36,000/kW_e. The other assumptions (maintenance and operation costs and number of full load hours) are assumed to be equal to the assumptions of the 10 MW_e installation. By assuming a cost level of a commercial installation of 10 MW_e, an attempt is made to separate the project-specific innovation costs from the total investment cost as well as possible. Table 45 provides an overview of the technical-economic parameters.

Table 45: Technical-economic parameters of osmosis

Parameter	Unit	Advice 2013
Installation size	[MW]	1
Investment cost	[€/kW$_e$]	36000
Full load hours	[h/a]	8000
Fixed O&M costs	[€/kW$_e$/a]	130
Variable O&M costs	[€/kWh]	0

7

Overview of base rates

Based on the technical-economic parameters of the various options, which are discussed in Chapter 6, base rates have been calculated by means of cash flow models. These models can be viewed here: http://www.ecn.nl/nl/units/ps/themas/hernieuwbare-energie/projecten/sde/sde-2013/.

Table 46 contains an overview of base rates for biomass digestion in this advice. The market consultation made it clear that the benefits of scale anticipated by ECN and DNV KEMA were considered unlikely. Based on the received responses, the overall costs of the hubs were increased . As a result, apart from a few exceptions, the hubs require higher base rates than an independently operating digestion installation.

Table 46: Overview of advised base rates for 2013 for biomass digestion

	Hub	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
All-feedstock digestion (stand-alone)	No	*Heat*	14.7	[€/GJ]	7000	-
	No	*CHP*	26.0	[€/GJ]	8000 / 4000	5739
	No	*Green gas*	59.4	[€ct/Nm^3]	8000	-
All-feedstock digestion (hub application)	Yes	*Heat*	17.7	[€/GJ]	7000	-
	Yes	*CHP*	29.1	[€/GJ]	8000 / 4000	5741
	Yes	*Green gas*	66.4	[€ct/Nm^3]	8000	-
Manure co-digestion (stand-alone)	No	*Heat*	20.6	[€/GJ]	7000	-
	No	*CHP*	31.1	[€/GJ]	8000 / 4000	5732
	No	*Green gas*	74.0	[€ct/Nm^3]	8000	-
Manure co-digestion (hub application)	Yes	*Heat*	21.9	[€/GJ]	7000	-
	Yes	*CHP*	34.9	[€/GJ]	8000 / 4000	5741
	Yes	*Green gas*	78.9	[€ct/Nm^3]	8000	-
Manure monodigestion (stand-alone)	No	*Heat*	23.1	[€/GJ]	7000	-
	No	*Electricity*	23.5	[€ct/kWh]	8000	-

	Hub	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
	No	*Green gas*	84.0	[€ct/Nm^3]	8000	-
Manure monodigestion (hub application)	Yes	*Heat*	25.2	[€/GJ]	7000	-
	Yes	*CHP*	37.1	[€/GJ]	8000 / 4000	5741
	Yes	*Green gas*	83.6	[€ct/Nm^3]	8000	-
WWTP (thermal pressure hydrolysis)	No	*Electricity*	9.6	[€ct/kWh]	8000	-
WWTP (replacement of gas engine)	No	*CHP*	6.4	[€/GJ]	8000 / 4000	5751
	No	*Green gas*	31.2	[€ct/Nm^3]	8000	-
	Yes	*Heat*	2.4	[€/GJ]	7000	-
	Yes	*Green gas*	20.1	[€ct/Nm^3]	8000	-
All-feedstock digestion (extended life)	No	*CHP*	22.5	[€/GJ]	8000 / 4000	5749
All-feedstock digestion (extended life)	Yes	*Green gas*	56.7	[€ct/Nm^3]	8000	-
All-feedstock digestion (extended life)	Yes	*Heat*	14.2	[€/GJ]	7000	-
Manure co-digestion (extended life)	No	*CHP*	26.4	[€/GJ]	8000 / 4000	5749
Manure co-digestion (extended life)	Yes	*Green gas*	65.6	[€ct/Nm^3]	8000	-
Manure co-digestion (extended life)	Yes	*Heat*	17.1	[€/GJ]	7000	-
Heat utilisation existing all-feedstock digestion	No	*Heat*	6.3	[€/GJ]	7000	-
Heat utilisation existing manure co-digestion	No	*Heat*	8.2	[€/GJ]	4000	-
Heat utilisation in composting	No	*Heat*	4.4	[€/GJ]	7000	-

* Note on CHP options: Full load hours electricity/full load hours useful heat utilisation. See also Chapter 4.

The base rates for thermal conversion of biomass are included in Table 47. For biomass gasification a large-scale installation was assessed. New projects may be set up as demo at first and therefore become more expensive. However, the base rate is the representative cost level for large-scale roll-out.

Table 47: Overview of advised base rates for 2013 for thermal biomass conversion

	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled?
Gasification	*Green gas*	123.4	[€ct/Nm^3]	7500	-
Thermal conversion < 10 MW_e	*CHP*	40.9	[€/GJ]	8000/4000	4241
Thermal conversion > 10 MW_e	*CHP*	21.8	[€/GJ]	7500/7500	7500
Extended life of incineration plants	*CHP*	18.7	[€/GJ]	8000/4000	4429
Boiler fired by solid biomass	*Heat*	11.5	[€/GJ]	7000	-
Boiler fired by liquid biomass	*Heat*	21.7	[€/GJ]	7000	-
Heat utilisation existing waste incineration plants	*Heat*	6.3	[€/GJ]	7000	-
Heat utilisation existing incineration plants	*Heat*	6.3	[€/GJ]	7000	-

* Note on CHP options: Full load hours electricity/full load hours useful heat utilisation. See also Chapter 4.

The techniques that are not based on biomass are listed in Table 48.

Compared to the final advice of SDE+ 2012, the reference installation for geothermal heat is better tailored to heat supply in greenhouse horticulture. This has led to higher base rates at fewer full load hours, resulting in a lower absolute compensation.

Table 48: Overview of advised base rates for 2013 for other options

	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled?
Geothermal energy and heat					
Deep geothermal energy	*Heat*	11.8	[€/GJ]	5500	-
Deep geothermal energy	*CHP*	24.0	[€/GJ]	5000 / 4000	4158
Wind energy					
Onshore wind, extremely rich in wind	*Electricity*	7.0	[€ct/kWh]	3300	-
Onshore wind, very rich in wind	*Electricity*	8.0	[€ct/kWh]	2800	
Onshore wind, rich in wind	*Electricity*	9.0	[€ct/kWh]	2400	
Onshore wind, low-wind	*Electricity*	9.5	[€ct/kWh]	2200	-
Onshore wind ≥ 6 MW	*Electricity*	9.3	[€ct/kWh]	3000	-
Onshore wind ≥ 6 MW (variant 1)	*Electricity*	9.0	[€ct/kWh]	3130	-
Onshore wind ≥ 6 MW (variant 2)	*Electricity*	8.0	[€ct/kWh]	3600	-
Wind in lake	*Electricity*	12.2	[€ct/kWh]	3200	-

	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled?
Offshore wind	*Electricity*	16.0	[€ct/kWh]	4000	-
Hydro energy					
Low fall of height (< 5 m)	*Electricity*	11.8	[€ct/kWh]	7000	-
Existing water management facilities	*Electricity*	6.2	[€ct/kWh]	4300	-
Free tidal current energy	*Electricity*	25.5	[€ct/kWh]	2800	-
Osmosis	*Electricity*	49.3	[€ct/kWh]	8000	-
Solar energy					
Solar PV (> 15 kW_p)	*Electricity*	14.8	[€ct/kWh]	1000	-
Solar thermal	*Heat*	33.3	[€/GJ]	700	-

* Note on CHP options: Full load hours electricity/full load hours heat supply. See also Chapter 4.

For some categories, the calculated base rates are higher than 15 €ct/kWh, which is the upper limit in the SDE+ scheme. The base rates of these options, i.e. onshore wind, free tidal current energy, osmosis and gasification, have been based on indicative calculations. The cost developments in offshore wind are such that in the coming years the base rate may drop below 15 €ct/kWh after all.

The base rates mentioned in this report are based on representative installations. In reality, costs may be lower or higher in some instances due to local conditions.

Abbreviations

AVI	Waste incineration installation
BEC	Bio-energy plant
BEMS	Decree on emission regulation mid-sized combustion plants
CAR	*Construction all risk,* construction insurance
COP	*Coefficient of performance*
EEG	*Erneurbare-Energien-Gesetz*
EIA	Energy Investment Tax Deduction
EL&I	Dutch Ministry of Economic Affairs, Agriculture and Innovation
ETS	*Emissions Trading System*
GoO	Guarantees of origin
IEA	International Energy Agency
IRE	Energy saving investment scheme
LEI	Agricultural Economics Research Institute
MEI	Market introduction of energy innovations
MEP	Environmental Quality of Electricity production
MER	Environmental impact report
MIA	Tax refund on environmental investment
NWEA	Dutch Wind Energy Association
O&M	*Operation & Maintenance*
ORC	Organic Rankine cycle
OT	Unprofitable gap
PS	Process steam
SDE	Dutch Renewable Energy Support Scheme
SNG	*Substitute Natural Gas or Synthetic Natural Gas*
VLU	Full load hours
CHP	Combined Heat and Power

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Appendix A. Additional financial instruments

In the calculation of the base rates the benefits following from schemes such as EIA (Energy Investment Tax Deduction) and green investments are deducted from the base rates to the extent that these benefits apply generically to a category and to the extent that the reference installation meets the criteria of the EIA scheme. Tables 49, 50 and 51 show the manner in which these benefits are weighed in the calculations.

Table 49: Overview of additional financial instruments in SDE+ 2013 for biomass digestion

	Hub	Energy product	EIA	Green investment
All-feedstock digestion (stand-alone)	No	*Heat*	No	No
	No	*CHP*	Yes, excl. digester	No
	No	*Green gas*	Yes, excl. digester	No
All-feedstock digestion (hub application)	Yes	*Heat*	Hub	No
	Yes	*CHP*	Hub	No
	Yes	*Green gas*	Hub	No
Manure co-digestion (stand-alone)	No	*Heat*	No	No
	No	*CHP*	Yes, excl. digester	No
	No	*Green gas*	Yes, excl. digester	No
Manure co-digestion (hub application)	Yes	*Heat*	Hub	No
	Yes	*CHP*	Hub	No
	Yes	*Green gas*	Hub	No
Manure mono-digestion (stand-alone)	No	*Heat*	No	No
	No	*Electricity*	No	No
	No	*Green gas*	Yes, excl. digester	No
Manure mono-digestion (hub application)	Yes	*Heat*	Hub	No
	Yes	*CHP*	Hub	No
	Yes	*Green gas*	Hub	No
WWTP (thermal pressure hydrolysis)	No	*Electricity*	No	No
WWTP (replacement of gas engine)	No	*CHP*	No	No
	No	*Green gas*	Yes, excl. digester	No
	Yes	*Heat*	Hub	No
	Yes	*Green gas*	Hub	No
All-feedstock digestion (extended life)	No	*CHP*	No	No
All-feedstock digestion (extended life)	Yes	*Green gas*	Hub	No

	Hub	Energy product	EIA	Green investment
All-feedstock digestion (extended life)	Yes	*Heat*	Hub	No
Manure co-digestion (extended life)	No	*CHP*	No	No
Manure co-digestion (extended life)	Yes	*Green gas*	Hub	No
Manure co-digestion (extended life)	Yes	*Heat*	Hub	No
Heat utilisation existing all-feedstock digestion	No	*Heat*	Yes	No
Heat utilisation existing manure co-digestion	No	*Heat*	No	No
Heat utilisation in composting	No	*Heat*	Yes	No

Table 50: Overview of additional financial instruments in SDE+ 2013 for thermal conversion of biomass

	Energy product	EIA	Green investment
Gasification	*Green gas*	Yes	Yes
Thermal conversion <(10 MW_e)	*CHP*	No	No
Thermal conversion (> 10 MW_e)	*CHP*	Yes	No
Extended life of incineration plants	*CHP*	No	No
Boiler fired by solid biomass	*Heat*	Yes	No
Boiler fired by liquid biomass	*Heat*	Yes	No
Heat utilisation existing waste incineration plants	*Heat*	Yes	No
Heat utilisation existing incineration plants	*Heat*	Yes	No

Table 51: Overview of additional financial instruments for SDE+ 2013 for other options

	Energy product	EIA	Green investment
Geothermal energy and heat			
Deep geothermal energy	*Heat*	Yes	Yes
Deep geothermal energy	*CHP*	Yes	Yes
Wind energy			
Onshore wind, extremely rich in wind	*Electricity*	Up to 600 €/kW_e	Yes
Onshore wind, very rich in wind	*Electricity*	Up to 600 €/kW_e	Yes
Onshore wind, rich in wind	*Electricity*	Up to 600 €/kW_e	Yes
Onshore wind, low-wind	*Electricity*	Up to 600 €/kW_e	Yes
Onshore wind ≥ 6 MW	*Electricity*	Up to 600 €/kW_e	Yes
Wind in lake	*Electricity*	Up to 600 €/kW_e	Yes
Offshore wind	*Electricity*	Up to 1000 €/kW_e	Yes
Hydro energy			
Low height of fall (< 5 m)	*Electricity*	Yes	Yes
Existing water management facilities	*Electricity*	Yes	Yes
Free tidal current energy	*Electricity*	Yes	Yes
Osmosis	*Electricity*	Yes	Yes
Solar energy			
Solar PV (> 15 kW_p)	*Electricity*	Yes	Yes
Solar thermal	*Heat*	Yes	Yes

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