Final advice base rates SDE+ 2014

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Abstract

On assignment of the Dutch Ministry of Economic Affairs, ECN and DNV KEMA have studied the cost of renewable electricity production. This cost assessment for various categories is part of advice on the subsidy base rates for the feed-in support scheme SDE+. This report contains the advice on the cost of projects in the Netherlands targeted for realization in 2014, covering installation technologies for the production of green gas, biogas, renewable electricity and renewable heat. A draft version of this advice has been discussed with the market in an open consultation round. Dr Pehnt from IFEU (Institut für Energie- und Umweltforschung Heidelberg) has conducted an external review of this advice.

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Summary

The Dutch Ministry of Economic Affairs asked ECN and DNV KEMA to advise on the base rates for 2014. The part on geothermal in this advice has been jointly written by ECN, DNV KEMA and TNO. This report contains the final advice on the base rates, which have been established after consulting market parties. The base rates have been calculated such that they are sufficient for the majority of the projects in the respective category. Due to project-specific circumstances, some initiatives may turn out to be unprofitable in realisation despite the SDE+ compensation. Table 1 shows the overview of base rates for thermal conversion of biomass. A significant difference compared to the draft advice is the splitting up of the category of boilers fired by solid biomass into two categories with a capacity of 5 MW_{th} as separator.

Table 1: Overview of advised base rates SDE+ 2014 for thermal biomass conversion

	Energy product	Base rate	Unit	Full load hours	Full load hours compiled
Gasification	*Green gas*	129.1	[€ct/Nm^3]	7500	-
Thermal conversion (< 10 MW_e)	*CHP*	40.9	[€/GJ]	8000/4000	4241
Thermal conversion (> 10 MW_e)	*CHP*	22.7	[€/GJ]	7500/7500	7500
Boiler fired by solid biomass < 5 MW_{th}	*Heat*	14.2	[€/GJ]	4000	-
Boiler fired by solid biomass ≥ 5 MW_{th}	*Water*	11.8	[€/GJ]	7000	
Boiler fired by liquid biomass	*Water*	19.8	[€/GJ]	7000	-
Heat in existing WIPs	*Water*	6.4	[€/GJ]	7000	-
Heat utilisation existing incineration plants	*Water*	6.4	[€/GJ]	7000	-

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

Table 2 shows an overview of biomass digestion in stand-alone plants and Table 3 shows the overview of the other options. For some categories, the calculated base rates significantly exceed 15 €ct/kWh (103.53 €ct/Nm^3 for green gas and 41.7 €/GJ for heat), the upper limit in the SDE+. The base rates of these options, i.e. osmosis and free tidal current energy, have been based on indicative calculations.

Separate advice will be prepared for the base rate for extended life of incineration installations, because ECN and DNV KEMA deem further consultations with the market necessary. Moreover, the discussions with market parties on the base rates for manure mono-digestion and WWTP have led to a significant increase in the base rates compared to the draft advice.

In general, many of the base rates are slightly higher compared to the draft advice, because calculations now include the abolishment of EIA for installations that are eligible for receiving SDE subsidy.

Table 2: Overview of advised base rates SDE+ 2014 for biomass digestion in a stand-alone installation

	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
All-feedstock digestion (stand-alone)	*Water*	14.7	[€/GJ]	7000	-
	CHP	26.3	[€/GJ]	8000 / 4000	5739
	Green gas	60.1	[€ct/Nm^3]	8000	-
Manure co-digestion (stand-alone)	*Water*	20.6	[€/GJ]	7000	-
	CHP	31.4	[€/GJ]	8000 / 4000	5732
	Green gas	75.0	[€ct/Nm^3]	8000	-
Manure mono-digestion (stand-alone)	*Water*	27.4	[€/GJ]	7000	-
	Electricity	28.9	[€ct/kWh]	8000	-
	Green gas	104.4	[€ct/Nm^3]	8000	-
WWTP (thermal pressure hydrolysis)	*Electricity*	9.6	[€ct/kWh]	8000	-
WWTP	*CHP*[1]	8.5	[€/GJ]	8000 / 4000	5751
	Green gas	33.3	[€ct/Nm^3]	8000	-
All-feedstock digestion (extended life)	*CHP*	24.1	[€/GJ]	8000 / 4000	5855
	Heat (hub)	16.0	[€/GJ]	7000	-
	Green gas (hub)	61.9	[€ct/Nm^3]	8000	-
Agricultural digesters (extended life)	*CHP*	28.2	[€/GJ]	8000 / 4000	5855
	Heat (hub)	18.8	[€/GJ]	7000	-
	Green gas (hub)	71.0	[€ct/Nm^3]	8000	-
Heat utilisation existing all-feedstock digestion	*Water*	6.4	[€/GJ]	7000	-
Heat utilisation existing agricultural digesters	*Water*	8.2	[€/GJ]	4000	-
Heat utilisation in composting	*Water*	4.6	[€/GJ]	7000	-
Downstream ORC	*Electricity*	6.2	[€ct/kWh]	8000	-

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

1 Also representative of thermophilic digestion.

Table 3: Overview of advised SDE+ base rates for 2014 for other options

	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
Geothermal energy and heat					
Deep geothermal (low temperature)	*Water*	11.9	[€/GJ]	6000	-
Deep geothermal (high temperature)	*Water*	14.4	[€/GJ]	7000	-
Deep geothermal energy	*CHP*	25.8	[€/GJ]	5000 / 4000	4158
Wind energy					
Onshore wind (stage I)	*Electricity*	7.0	[€ct/kWh]	3500	-
Onshore wind (stage II)	*Electricity*	8.0	[€ct/kWh]	2850	
Onshore wind (stage III)	*Electricity*	9.0	[€ct/kWh]	2450	
Onshore wind ≥ 6 MW (stage II)	*Electricity*	8.0	[€ct/kWh]	3700	-
Onshore wind ≥ 6 MW (stage II)	*Electricity*	9.0	[€ct/kWh]	3150	-
Onshore wind ≥ 6 MW (stage IV)	*Electricity*	9.7	[€ct/kWh]	2900	-
Wind in lake	*Electricity*	12.3	[€ct/kWh]	3200	-
Offshore wind	*Electricity*	15.7	[€ct/kWh]	3750	-
Hydro energy					
Hydropower new	*Electricity*	16.6	[€ct/kWh]	5700	-
Hydropower renovation	*Electricity*	6.6	[€ct/kWh]	4300	-
Free tidal current energy	*Electricity*	27.6	[€ct/kWh]	2800	-
Osmosis	*Electricity*	54.4	[€ct/kWh]	8000	-
Solar energy					
Solar PV (> 15 kWp)	*Electricity*	14.7	[€ct/kWh]	1000	-
Solar thermal	*Water*	38.2	[€/GJ]	700	-

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

1 Introduction

The Dutch Ministry of Economic Affairs has requested ECN and DNV KEMA to advise on the height of the base rates in the framework of the SDE+ scheme for 2014. As with comparable studies in previous years, ECN and DNV KEMA, in consultation with the ministry, decided to present a draft advice to the market. Last June, the market was consulted. This report contains the final advice, in which the feedback of the market parties has been weighed and included based on the insights of ECN and DNV KEMA.

ECN and DNV KEMA advise the ministry on the height of the base rates for SDE+ 2014.

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 Economic Affairs decides on the opening of the SDE+ scheme in 2014, on the categories to be opened and on the base rates for the new SDE+ allowances in 2014.

Reading instructions

Chapter 2 describes the process; Chapter 3 discusses the price developments for electricity, gas and biomass. Chapter 4 provides overviews of the technical-economic parameters of the renewable energy options per category. Chapter 5 contains the conclusions, in which the translation into base rates is done based on brief descriptions of the financial parameters.

2

Process and starting points

2.1 Process

26 consultation meetings were held based on the draft advice.

The draft advice was published on 13 May 2013 to serve as input for the public market consultation. To this end an information meeting was held for branch organisations at the Dutch Ministry of Economic Affairs on 13 May 2013. This draft report was used to invite market parties to send their responses to ECN. On 14 June 2013, about 40 consultation responses had been received, followed by 26 consultation discussions that were held in the period 17 June to 5 July.

After the market consultation, ECN and DNV KEMA drafted this final advice. Both the final advice, and the process and method used by ECN and DNV KEMA to weigh the market responses, have been subjected to an external review by a reviewer appointed by the Ministry. The review was conducted by the German institute IFEU (Institut für Energie- und Umweltforschung Heidelberg). On 8 August, the draft advice as well as the manner in which the authors had conducted the consultation process were discussed by the authors and the reviewer. This advice was finished on 11 September.

2.2 Working method and starting points

The Dutch Ministry of Economic Affairs asked ECN and DNV KEMA to establish the base rates for the SDE+ scheme for 2014. The advice on geothermal was drafted by ECN, DNV KEMA and TNO. The base rates to be advised on include the production costs of renewable energy carriers, plus any scheme-specific additional costs related to closing electricity, heat or gas contracts. The ministry listed the categories in the request for advice. ECN and DNV KEMA calculated the production costs of renewable electricity, green gas and renewable heat for all categories. The Minister of Economic Affairs 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. 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.

The rule of thumb is that the majority of the projects 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. The Ministry of Economic Affairs sees to it that the calculated production costs do justice to the provisions of the European Commission with regard to 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.

The SDE+ scheme reimburses the difference between the base rate (the production costs of renewable electricity, renewable heat and green gas) on the one hand and the correction amount (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 as 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 an optional heat distribution pipe is included in the investment cost of the project. The heat infrastructure on the demand side, 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.

On request of the Ministry, the calculations have been based on the assumption that there are no benefits to be gained from the EIA scheme.

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 as these costs are not included in the total investment amount. If the green soft-loan scheme applied generically to a category in the past year, ECN and DNV KEMA need to include this benefit in the final advice. The green scheme assumes an interest benefit of 1%. On request of the Ministry, possible benefits from the EIA scheme (Energy Investment Tax Deduction) are not included in the calculations.

For 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 are assumed to be equal to the subsidy duration. In practise, some of the components of techniques such as hydropower and geothermal have a much longer life than 15 years. Therefore their investment costs are corrected for the remaining 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 between the lender and the project developer does not influence the advised base rates under the given starting points.

3

Prices for electricity and biomass

3.1 Electricity prices

The base rates are a measure for the production costs of renewable energy. 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. An example of such installations are green gas installations that 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, 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.

The used electricity price is only relevant in case of additional electricity demand, as for example in the case of gas upgrading.

3.2 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.

3.2.1 Solid biomass: Pruning and thinning wood

Pruning and thinning wood is the reference fuel for new installations for thermal conversion of solid biomass and for boilers fired by solid biomass. This has remained unchanged compared to the advice for the SDE+ 2013. The biomass consists of fresh wood chips from forests, landscapes and gardens. The energy content of fresh wood is

The price of pruning and thinning wood has remained unaltered compared to the advice for SDE+ 2013.

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 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. As pruning and thinning wood mainly address a local market, the risk surcharge that applies to cutting and thinning wood also applies here. The category of pruning and thinning wood is assumed to have a risk surcharge of 1 €/tonne.

3.2.2 Liquid biomass

After showing a peak in 2011 and 2012, the prices of vegetable oil and animal fats are showing a downward trend. Based on price developments up to August 2013, it was found that the prices for vegetable oils and animal fats are on average 10% lower compared to the same period in 2012. Given this tendency, the average expected price for 2014 is lowered by 10% to 600 €/tonne at a heating value of 39 GJ/tonne. The prices of animal fats are following the movements of 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.

3.2.3 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+ 2014 is assumed to be similar to the price of SDE+ 2013 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.

3.2.4 Digestion: Biomass for manure co-digesters

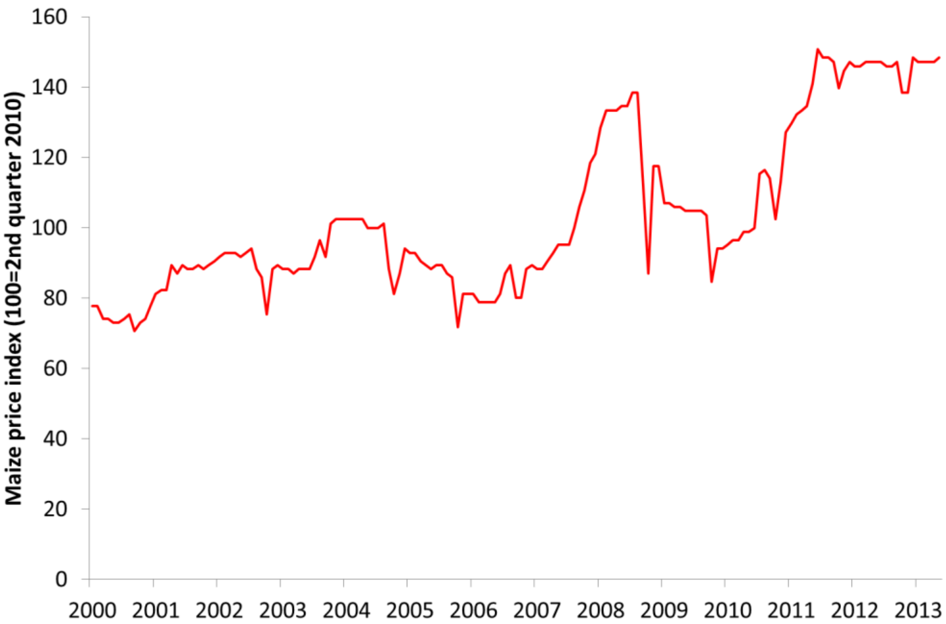
Feedstocks for manure co-digestion: manure

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 has been expanded with 80 new products in 2012. By allowing these co-products, a better alignment is realised 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.

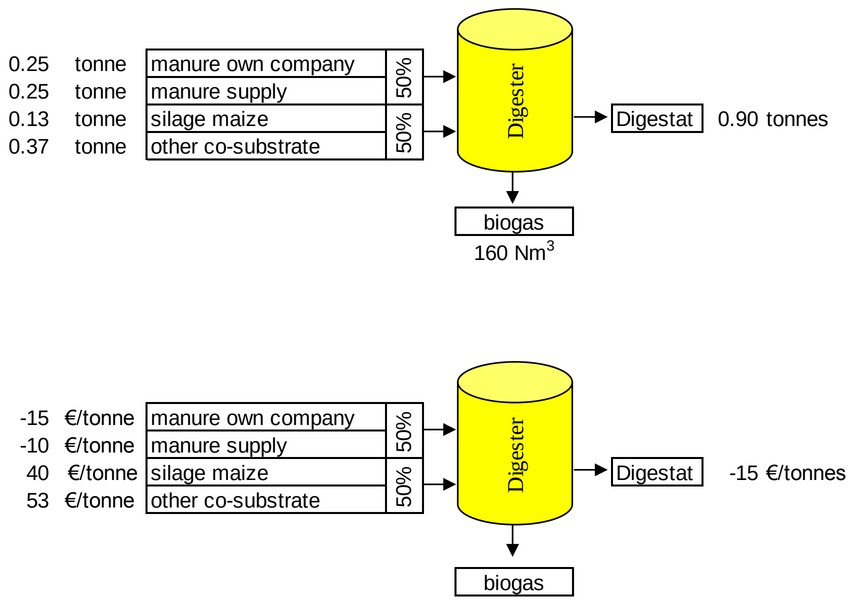
Figure 1: Indexed maize prices 1996-2012 based on LEI prices, index = 100 for the second quarter of 2010



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 June 2008 2007 up to June 2012 amounts to 40.1 €/tonne.

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[2]



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. The average price of co-substrate (excluding maize) in 2013 is 7.65 €/GJ or 53 €/tonne at the start of the project, with a net gas yield of 6.9 GJ/tonne. The total assumed feedstock costs, consisting of the purchase of maize, co-substrate and processing costs for manure and digestate, in the current mix amount to 32.1 €/tonne, or 20 ct/Nm^3 crude biogas, calculating with a gas yield of the total input, manure and co-substrate of 3.4 GJ/tonne. The total feedstock costs concur with the mentioned costs in the recent market consultation.

In view of price developments during the project, all cost items will be indexed with 2%/year for inflation. This also applies to the feedstock costs. Table 5.1 offers an overview of the used prices for the reference fuels.

2 The calculation method assumes the method that is common for the market, i.e. to express 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 or gas yield per tonne of input. To be more precise: tonnes of input are based on the entire product, not on the dry matter content alone.

Table 4: Used biomass prices for installations applying for SDE+ in 2014

	Energy content	Price (range)	Reference price	Explanation
	[GJ/tonne]	[€/tonne]	[€/GJ]	
Liquid biomass				
Animal fat	39	600	15.4	
Solid biomass				
Pruning and thinning wood	9	48	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*	*40.1 (25-45)*	*10.1*	
Other co-substrate	*6.9*	*53 (23 to 200)*	*7.65*	
Co-digestion input	3.4	32.1 (14-32)	9.5	

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

4

Technical-economic parameters

Indicative calculations have been made for higher cost options with a base rate of over 15 €ct/kWh

In the following sections, the underlying parameters used to determine 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. The discussed techniques are digestion of biomass, including waste water treatment plants and composting heat, thermal conversion of biomass, boiler fired with solid biomass, boiler fired with liquid biomass, existing installations, hydropower, wind energy, deep geothermal, solar PV, solar thermal and indicative calculations for more expensive options.

4.1 Hubs and the production of crude biogas

4.1.1 Introduction

Most base rates have been calculated based on the cost structure of a stand-alone installation, i.e. without hub connection.

Crude biogas, contrary to green gas, does not meet the specifications required to be fed into the natural gas grid. 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. Calculations for most categories are based on the costs of the processing of crude biogas into heat, electricity or green gas on site. For some categories, processing through a hub seems the more likely option (extended life of all-feedstock digesters, manure co-digesters and agricultural digesters that can choose to not only replace the CHP installation). Therefore, this section first discusses the technical-economic parameters of hubs.

4.1.2 Reference systems for production of crude biogas

In the establishing of the technical-economic parameters for the production of crude biogas, the costs of CO_2 separation are not included. Moreover, the costs of hydrogen sulphide or ammonia removal are discounted in the cost of the digester. In addition, it is assumed that part of the crude biogas is incinerated in a boiler to supply heat for the digester. The electricity for the installation is purchased and these costs are included in the O&M costs.

4.1.3 Description of reference CHP hub

The technical-economic parameters for the reference CHP hub, including biogas pipeline, are illustrated in Table 5. These parameters result in a cost price for a CHP hub of 6.0 €/GJ. The biogas is converted into heat and power with an annual average efficiency of 61% for end use.

Table 5: Technical-economic parameters CHP hub

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	12.7	
Electrical 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		-	
Investment cost	[€/kW_{th_input}]	445	€5.7 mln
Fixed O&M costs	[€/kW_{th_input}]	37	€ 470,000/year
Variable O&M costs (electricity)	[€/kWh_e]	-	
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	
Production costs	[€/GJ]	6.0	

4.1.4 Description of reference heat hub

The technical-economic parameters for the reference heat hub, including biogas pipe, are indicated in Table 6. These parameters result in a cost price of a heat hub of 1.1 €/GJ. The biogas is converted into heat with an annual average efficiency of 90% for end use.

Table 6: Technical-economic parameters heat hub

Parameter	Unit	Advice 2014	Total amount for reference
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	€1.4 mln
Fixed O&M costs	[$€/kW_{th\_output}$]	1.7	€ 19,000/year
Variable O&M costs (heat)	[€/GJ]	0.08	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	
Production costs	[€/GJ]	1.1	

4.1.5 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 Nm3/h of green gas) using gas cleaning by means of chemicals as gas cleaning technique. The heat that is needed for this technique is generated by firing part of the crude biogas in a boiler. The needed electricity is purchased.

The technical-economic parameters for the reference green gas hub, including biogas pipeline and green gas compression up to 40 bar, are illustrated in Table 7. These parameters result in a cost price of a green gas hub of 16.7 €ct/Nm^3. The biogas is converted into green gas at an annual average efficiency of almost 90%.

Table 7: Technical-economic parameters green gas hub

Parameter	Unit	Advice 2014	Total amount for reference
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 cost	[€/tonne]	n.a.	
Feedstock price surcharge	[€/tonne]	n.a.	
Investment cost	[€ per Nm^3_{biogas}/h]	2270	€4.5 mln
Fixed O&M costs	[€/a per Nm^3_{biogas}/h]	190	€ 376,000/year
Efficiency gas cleaning	[% methane]	99.9%	
Production costs	[€ct/Nm^3]	16.7	

4.2 WWTP

4.2.1 Reference installations

ECN and DNV KEMA use two reference installations for the WWTP category: the production of renewable energy when replacing an existing gas engine, and expansion of the capacity by means of thermal pressure hydrolysis[3]. With these two references, ECN and DNV KEMA aim to describe both the situation of a water treatment plant where investments in renewable energy production were previously made, and which currently has a need for a replacement investment, and the situation of a water treatment plant in which the deployment of new technology may lead to more renewable energy production from an existing treatment plant. During the consultation round specific attention was paid to the category for incentivising the generation of renewable energy from existing WWTP digestion installations.

During the consultation round, additional attention was paid to sustainable energy in existing WWTPs.

New-build

A reference installation with a capacity of about 200 kW_e will require an investment in a new digester to the amount of about 2 million euros. Adding a digestion installation to an existing WWTP does not only yield additional renewable energy production; the digestion of sludge also has benefits for the primary process of water purification. Among other things, the digestion leads to lower sludge production and the remaining sludge digestate can be dehydrated more successfully. The improved dehydration and reduced sludge production lead to savings in the operating expenses of the filter presses and in the transportation and final processing costs of the sludge digestate. District water boards have provided data of a business vase for the construction of a new digestion installation. Analysis by ECN and DNV KEMA shows that, after correction for the costs of water purification and allocating benefits of sludge processing, the construction of a new digestion installation with a CHP is profitable.

Renovation

By renovating existing digestion installations, the renewable energy generation at a WWTP can be increased by means of efficiency improvement and by increasing gas production. Replacement of old gas engines with new more efficient engines will increase the electricity production. Renovation of the digester, and possibly a conversion into a thermophilic digester, may further increase the gas production. When using modern gas engines with a higher efficiency, the crude biogas that is produced in the digestion of sewage sludge will need to be subjected to an additional purification step. That is why in the calculation an additional investment entry has been included for investment in an activated carbon filter and the O&M costs are raised due to the use of activated coal of the filters.

Regarding the replacement of the gas engine, it is assumed that this will be done on site: replacing the installation's own CHP by linking to a CHP hub is less obvious due to the high electricity use of the installation. If the renovation leads to higher gas

3 In addition, the cost structure of thermophilic digestion has been examined. In the production costs of sustainable energy, this is comparable to the replacement of an existing gas engine.

production, this may lead to a surplus of biogas. This surplus may arise if the capacity of the new gas engine is insufficient to utilise all the biogas. This surplus could, for instance, be deployed in biogas hubs. In the generic calculation of the base rates, however, it is assumed that all the gas that is produced is deployed in a new gas engine. An independent installation that fully converts water purification gas into heat is profitable; for comparison check the calculation of a connection to a heat hub. That is why the categories for heat production and for a CHP hub for WWTPs are not calculated.

4.2.2 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 water purification plants. The heat that is needed for this technique is generated by firing part of the crude biogas in a boiler. The waste 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 8 shows the technical-economic parameters for the production of crude biogas and green gas.

Table 8: Technical-economical parameters for WWTP (green gas)

Parameter	Unit	Advice 2014	Total amount for reference
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 costs (digester)	[€ per Nm^3_{biogas}/h]	-	€0.64 mln combined
Investment cost (gas upgrading)	[€ per Nm^3_{biogas}/h]	7515	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	-	€ 43,000/year combined
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	506	
Energy content substrate	[GJ_{biogas}/tonne]	22	
Feedstock cost	[€/tonne]	n.a.	
Feedstock price surcharge	[€/tonne]	n.a.	
Efficiency gas cleaning	[% methane]	99.9%	

4.2.3 Hub connection 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 9 and 10 show the technical-economic parameters of WWTP for crude biogas and CHP respectively. The CHP option includes usage of an activated carbon filter for the gas engine, both in the investment and in the O&M costs.

Table 9: Technical-economical parameters for WWTP (crude biogas) The column 'other' refers to the connection to a CHP or green gas hub.

Parameter	Unit	Advice 2014 (heat)	Advice 2014 (other)	Total amount for reference
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 costs (digester)	[€ per Nm^3_{biogas}/h]	-	-	
Investment cost (limited gas cleaning/gas drying)	[€ per Nm^3_{biogas}/h]	823	823	€0.074 mln combined
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	-	-	
Fixed O&M costs (limited gas cleaning/gas drying)	[€/a per Nm^3_{biogas}/h]	59	59	€ 5300/year combined
Energy content substrate	[GJ_{biogas}/tonne]	22	22	
Feedstock cost	[€/tonne]	n.a.	n.a.	
Feedstock price surcharge	[€/tonne]	n.a.	n.a.	
Efficiency gas cleaning	[% methane]	99.9%	99.9%	
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	4.4 / 1.4	3.9 / 1.2	
Base rate through heat hub (1.1 €/GJ hub and 90% efficiency)	[€/GJ]	2.6		
Base rate through green gas hub (16.7 €ct/GJ hub and 89.9% efficiency)	[€ct/Nm^3]		21.0	

Table 10: Technical-economical parameters for WWTP (CHP)

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	0.541	
Electrical 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	[%]	37%	
Electricity loss in heat supply		-	
Investment cost	[€/kW_{th_input}]	600	€0.32 mln
Fixed O&M costs	[€/kW_{th_input}]	57	€ 31,000/year
Variable O&M costs (electricity)	[€/kWh_e]	-	
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	22	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

4.2.4 Increasing the sludge digestion capacity in existing WWTPs by means of an upstream thermal pressure hydrolysis

The biogas production from waste water treatment plants can be increased by expanding an existing treatment plant with a thermal pressure hydrolysis installation. It is assumed that the existing treatment installation is already equipped with a CHP gas engine.

After hydrolysis, dehydration can be carried out, further reducing the sludge removal costs.

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 plant's own energy use. A new development in WWTPs is the expansion of these digestion installations with dehydration and hydrolysis 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 plant 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, which can be met by the 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 DNV KEMA conclude that only the 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 11.

Table 11: Technical-economic parameters WWTP (electricity from CHP with upstream thermal pressure hydrolysis)

Parameter	Unit	Advice 2014	Total amount for reference
Throughput of sludge	[tonne of dry matter/year]	16000	
Full load hours	[hour/year]	8000	
Gas yield	[Nm^3/ton]	170	
Gas yield	[Nm^3/hour]	340	
Calorific value of biogas	[MJ/Nm^3]	25	
CHP capacity (net)	[kW_e]	723	
Benefit of final processing	[€/tonne of dry matter input]	40	
Total investment	[€/kW_e]	6100	€4.4 mln
Total variable costs	[€/kW_e]	800	€ 578,000/year

4.3 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. In 2012, the Ministry of Economic Affairs asked ECN and DNV KEMA to deliver separate advice on the production costs for manure mono-digestion. Manure mono-digestion is still being developed and the gas yields are still too low.

Manure mono-digestion is still being developed.

4.3.1 The production of crude biogas

The reference system for this category has a crude biogas production of 20,5 Nm^3/h (or 11 Nm^3/h green gas). This is comparable to a CHP capacity of 39 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 a boiler. The required electricity is obtained from the grid.

Table 12 and Table 13 show the technical-economic parameters for the production of crude biogas and green gas. It should be noted that the base rates have been calculated on the basis of a stand-alone installation and on the basis of a hub connection.

Table 12: Technical-economical parameters for manure mono-digestion (crude biogas)

Parameter	Unit	Advice 2014 (heat)	Advice 2014 (other)	Total amount for reference
Reference size	[Nm^3_{biogas}/h]	20.5	20.5	
Full load hours	[h/a]	7000	8000	
Internal heat demand	[% biogas]	18%	18%	
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.12	0.12	
Electricity rate	[€/kWh]	0.16	0.16	
Investment costs (digester)	[€ per Nm^3_{biogas}/h]	14900	14900	€0.327 mln combined
Investment cost (limited gas cleaning/gas drying)	[€ per Nm^3_{biogas}/h]	1260	1260	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	807	807	€18,700/year combined
Fixed O&M costs (limited gas cleaning/gas drying)	[€/a per Nm^3_{biogas}/h]	126	126	
Energy content substrate	[GJ_{biogas}/tonne]	0.63	0.63	
Feedstock cost	[€/tonne]	n.a.	n.a.	
Feedstock price surcharge	[€/tonne]	n.a.	n.a.	
Efficiency gas cleaning	[% methane]	100.0%	100.0%	
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	84.5 / 26.7	74.3 / 23.5	
Base rate through heat hub (1.1 €/GJ hub and 90% efficiency)	[€/GJ]	30.7		
Base rate through CHP hub (6.0 €/GJ hub and 85% efficiency)			33.6	
Base rate through green gas hub (16.7 €ct/GJ hub and 89.9% efficiency)	[€/GJ]		99.3	

Table 13: Technical-economical parameters for manure mono-digestion (green gas)

Parameter	Unit	Advice 2014	Total amount for reference
Reference size	[Nm^3_{biogas}/h]	20.5	
Full load hours	[h/a]	8000	
Internal heat demand	[% biogas]	18%	
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.49	
Electricity rate	[€/kWh]	0.10	
Investment costs (digester)	[€ per Nm^3_{biogas}/h]	14900	€0.44 mln combined
Investment cost (gas upgrading)	[€ per Nm^3_{biogas}/h]	8300	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	807	€ 24,000/year combined
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	454	
Energy content substrate	[GJ_{biogas}/tonne]	0.63	
Feedstock cost	[€/tonne]	n.a.	
Feedstock price surcharge	[€/tonne]	n.a.	
Efficiency gas cleaning	[% methane]	99.0%	

4.3.2 Production of renewable heat and electricity

The reference installation for the production of renewable heat and electricity is based on the manure that is internally produced by the company. Based on the energy content of manure and the electrical efficiency of the gas engine, the reference installation delivers a net electrical output of 39 kW_e. Technically, electricity involves a CHP installation in which the 26 kW_{th} of heat is entirely deployed for the internal digestion process. This leaves only electricity to supply and to allocate SDE+ allowance to.

Table 14 and Table 15 show the technical-economic parameters of manure mono-digestion for heat and electricity, respectively.

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

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	0.123	
Full load hours heat supply	[h/a]	7000	
Internal heat demand	[% biogas]	18	
Internal electricity demand	[kWh/GJ_{output}]	5.41	
Electricity rate	[€/kWh]	0.16	
Investment cost	[$€/kW_{th\_output}$]	3340	€0.31 mln
Fixed O&M costs	[$€/kW_{th\_output}$]	187	€ 18,000/year
Variable O&M costs (heat)	[€/GJ]	0.87	
Energy content fuel	[GJ/tonne]	0.63	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

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

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	0.123	
Electrical capacity	[MW_e]	0.039	
Thermal output capacity	[MW_{th_output}]	0.026	
Full-load hours electricity supply	[h/a]	8000	
Full-load hours heat supply	[h/a]	0	
Maximum electrical efficiency	[%]	32%	
Electricity loss in heat supply		-	
Investment cost	[$€/kW_{th\_input}$]	3390	€0.42 mln
Fixed O&M costs	[$€/kW_{th\_input}$]	245	€ 30,000/year
Variable O&M costs (electricity)	[$€/kWh_e$]	-	
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	0.63	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

4.4 Manure co-digestion

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

4.4.1 The production of crude biogas and green gas

Recent initiatives for manure co-digesters mostly focus on the SDE category for production of renewable heat. Green gas projects or CHP initiatives are limited in number. 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 in case of larger scale production.

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 waste heat released during gas scrubbing is sufficient to heat the digester. The needed electricity is purchased. It is assumed that the produced green gas can be fed into the local 8 bar grid. Table 16 and Table 17 show the technical-economic parameters for the production of crude biogas and green gas. It should be noted that the base rates have been calculated on the basis of a stand-alone installation and on the basis of a hub connection.

Table 16: Technical-economic parameters manure co-digestion (crude biogas)

Parameter	Unit	Advice 2014 (heat)	Advice 2014 (other)	Total amount for reference
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 costs (digester)	[€ per Nm^3_{biogas}/h]	4500	4500	€2.4 mln combined
Investment cost (limited gas cleaning/gas drying)	[€ per Nm^3_{biogas}/h]	350	350	€2.4 mln combined
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	280	280	€ 158,000/year combined
Fixed O&M costs (limited gas cleaning/gas drying)	[€/a per Nm^3_{biogas}/h]	35	35	€ 158,000/year combined
Energy content substrate	[GJ_{biogas}/tonne]	3.40	3.40	
Feedstock cost	[€/tonne]	32.1	32.1	
Feedstock price surcharge	[€/tonne]	1	1	
Efficiency gas cleaning	[% methane]	100.0%	100.0%	
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	59.5 / 18.8	56.7 / 17.9	
Base rate through heat hub (1.1 €/GJ hub and 90% efficiency)	[€/GJ]	22.0		
Base rate through CHP hub (6.0 €/GJ hub and 85% efficiency)			27.1	
Base rate through green gas hub (16.7 €ct/GJ hub and 89.9% efficiency)	[€/GJ]		79.7	

Table 17: Technical-economic parameters manure co-digestion (green gas)

Parameter	Unit	Advice 2014	Total amount for reference
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 costs (digester)	[€ per Nm^3_{biogas}/h]	4500	€3.6 mln combined
Investment cost (gas upgrading)	[€ per Nm^3_{biogas}/h]	3020	€3.6 mln combined
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	280	€ 278,000/year combined
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	300	€ 278,000/year combined
Energy content substrate	[GJ_{biogas}/tonne]	3.40	
Feedstock cost	[€/tonne]	32.1	
Feedstock price surcharge	[€/tonne]	0.5	
Efficiency gas cleaning	[% methane]	99.9%	

4.4.2 Installations for renewable heat and CHP

Through the years, the composition of the co-substrate in manure co-digestion installations has changed, which has increased the gas yield per tonne of co-substrate substantially to over 100 Nm^3/tonne of the manure and co-substrate mix. In the last two years, new initiatives for manure digestion for electricity production had a scale size for CHP of 1 MW_e or smaller. The new renewable heat initiatives show a wider spread in scale size. For example, one out of eight initiatives has a scale size between 2 and 6 MW_{th}. The reference installation scale is assumed to be 1,1 MW_e (3 MW_{th_input}). 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 manure co-digestion for renewable heat, 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.

It is impossible to hedge all project risks in long-term contracts. There is some flexibility in the substrate mix, though.

The efficiency of the gas engine that is art of the CHP installation is calculated at a level that complies with the NO_x emission requirements from the Decree on emission limits for medium-sized combustion plants (BEMS). Calculations for the SDE+ base rates are based on 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 hedge 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 18 and Table 19.

Table 18: Technical-economical parameters for manure co-digestion (heat)

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	3.000	
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	€2.4 mln
Fixed O&M costs	[€/kW_{th_output}]	57	€146,000/year
Variable O&M costs (heat)	[€/GJ]	0.54	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	32.1	
Fuel surcharge	[€/tonne]	0.5	

Table 19: Technical-economic parameters manure co-digestion (CHP)

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	2.973	
Electrical capacity	[MW_e]	1.100	
Thermal output capacity	[MW_{th_output}]	1.440	
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}]	1150	€3.42 mln
Fixed O&M costs	[€/kW_{th_input}]	85	€253,000/year
Variable O&M costs (electricity)	[€/kWh_e]	-	
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	32.1	
Fuel surcharge	[€/tonne]	0.5	

4.5 All-feedstock digestion

4.5.1 The production of crude biogas and green gas

The reference technology for this category is a digester with various waste 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. Tables 20 and 21 show the technical-economic parameters for the production of crude biogas or green gas in all-feedstock digesters. It should be noted that the base rates have been calculated on the basis of a stand-alone installation and on the basis of a hub connection.

Table 20: Technical-economical parameters for all-feedstock digestion (crude biogas)

Parameter	Unit	Advice 2014 (heat)	Advice 2014 (other)	Total amount for reference
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 costs (digester)	[€ per Nm^3_{biogas}/h]	3900	3900	€4.0 mln combined
Investment cost (limited gas cleaning/gas drying)	[€ per Nm^3_{biogas}/h]	275	275	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	220	220	€232,000/year combined
Fixed O&M costs (limited gas cleaning/gas drying)	[€/a per Nm^3_{biogas}/h]	25	25	
Energy content substrate	[GJ_{biogas}/tonne]	3.4	3.4	
Feedstock cost	[€/tonne]	25	25	
Feedstock price surcharge	[€/tonne]	n.a.	n.a.	
Efficiency gas cleaning	[% methane]	100.0%	100.0%	
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	47.6 / 15	45.2 / 14.3	
Base rate through heat hub (1.1 €/GJ hub and 90% efficiency)	[€/GJ]	17.8		
Base rate through CHP hub (6.0 €/GJ hub and 85% efficiency)			22.8	
Base rate through green gas hub (16.7 €ct/GJ hub and 89.9% efficiency)	[€/GJ]		67.0	

Table 21: Technical-economical parameters for all-feedstock digestion (green gas)

Parameter	Unit	Advice 2014	Total amount for reference
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 costs (digester)	[€ per Nm^3_{biogas}/h]	3900	€5.8 mln combined
Investment cost (gas upgrading)	[€ per Nm^3_{biogas}/h]	2400	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	220	€414,000/year combined
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	240	
Energy content substrate	[GJ_{biogas}/tonne]	3.4	
Feedstock cost	[€/tonne]	25.0	
Feedstock price surcharge	[€/tonne]	n.a.	
Efficiency of gas cleaning	[% methane]	99.9%	

4.5.2 Installations for renewable heat and CHP

In this digestion option, an existing installation is modified, integrating a production installation for electricity or heat into 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.

The scale size of new CHP initiatives is smaller than or around 3 MW_e. One out of eight new renewable heat initiatives is around 5 MW_{th}. For the reference installation, a scale of 3 MW_e (8.1 MW_{th_input}) is assumed. 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 22 and Table 23.

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

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	8.100	
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	[$€/kW_{th\_output}$]	586	€4.1 mln
Fixed O&M costs	[$€/kW_{th\_output}$]	32	€ 222,000/year
Variable O&M costs (heat)	[€/GJ]	0.54	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	25.0	
Fuel surcharge	[€/tonne]	n.a.	

Table 12: Technical-economic parameters manure all-feedstock digestion (CHP)

Parameter	Unit	Advice 2014	Total amount for reference
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	€8.6 mln
Fixed O&M costs	[€/kW_{th_input}]	78	€ 632,000/year
Variable O&M costs (electricity)	[€/kWh_e]	-	
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	25.0	
Fuel surcharge	[€/tonne]	n.a.	

4.6 Thermal conversion of biomass

In thermal conversion of biomass, excluding gasification for green gas production and renewable heat installations, two system sizes are distinguished, with a boundary value of 10 MW_e.

4.6.1 Thermal conversion of biomass (< 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. The reference installation has a thermal output capacity of 8.7 MW_{th} with a maximum electricity supply of 1.65 MW_e and a maximum heat supply of 5 MW_{th}. Installations up to 10 MW_e must meet BEMS requirements, resulting in additional measures having to be taken to reduce the emission of nitrogen oxides, for example by means of a DeNOx installation. The investment cost amounts to 1550 €/kW_{th}. These costs are higher than previously assumed, which is due to the fact that in most cases licensing authorities 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.

4.6.2 Thermal conversion of biomass (> 10 MW_e)

The reference is a wood-fired installation with an input capacity of about 67 MW_{th}. 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 routes 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 of fresh wood flows, a larger storage and transport system is needed as well as a larger incineration component for the installation. The flue gas cleaning can be conducted relatively mildly, given that fresh wood contains significantly less harmful components than for example B-quality wood. The technical-economic data of these reference plants have been summarised in Table 24.

The reference is a back-pressure turbine fuelled by pruning and thinning wood.

Table 24: Technical-economic parameters of thermal conversion of biomass

Parameter	Unit	Advice 2014 (<10 m)	Advice 2014 (>10 m)	Total amount for reference
Input capacity	[MW_{th_input}]	8.7	67.9	
Electrical capacity	[MW_e]	1.7	9.5	
Thermal output capacity	[MW_{th_output}]	5.0	50.0	
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	€ 13.5 mln resp. € 125 mln
Fixed O&M costs	[€/kW_{th_input}]	80	110	€ 0.69 mln resp. € 7.5 mln
Variable O&M costs (electricity)	[€/kWh_e]	0.006	-	
Variable O&M costs (heat)	[€/GJ]	-	-	
Energy content fuel	[GJ/tonne]	9.0	9.0	
Fuel price	[€/tonne]	48	48	
Fuel surcharge	[€/tonne]	1.0	1.0	

4.7 Boiler on solid biomass

In the last two years, there has been an observable tendency of developing small-scale installations between 0.5 and 1 MW_{th}. Two system sizes are distinguished for boilers fired by solid biomass, with an upper limit of 5 MW_{th}.

Two system sizes are distinguished for boilers fired by solid biomass. This has changed compared to the draft advice.

4.7.1 Boiler on solid biomass > 0.5 MW_{th} and < 5MW_{th}

The reference installation for this category is a hot water boiler with a combustion grate, deploying wood from cutting and pruning as reference fuel. In 2013, the expected subsidy at a maximal operating time amounts to 39,000 euro per year for a 750 kW_{th} boiler. In practice, 7000 full load hours may not always be realised at this scale size. Therefore, initiatives in the scale size of 750 kWth which applied for SDE subsidy in 2013 will receive an estimated 20 to 38 thousand euros of subsidy per year.

In this advice for a base rate for 2014, the financial gap is calculated at 47 thousand euro per year for a 750 kW_{th} boiler. The number of full load hours for this category is assumed to be 4000 hours per year, rendering the maximum subsidy amount feasible for the majority of applicants. The increase on the total subsidy is justified by the additional investments that are needed to meet the emission requirements of the activities decree for particulate matter.

4.7.2 Boiler fired by solid biomass > 5 MW_{th}

The reference installation for this category is also a hot water boiler with a combustion grate, deploying wood from cutting and pruning as reference fuel. In 2013, the expected subsidy amounts to 513,000 euro per year for a boiler of 10 MW_{th} at 7000 full load hours, which, in practise, is feasible for projects of this scale-size. The correction amount in 2013 is based on small-scale heat supply.

Indications have been found that there are only few locations where a project can be realised with the subsidy amount of 2013.

In 2013, in the period up to 11 June, only four applications were submitted, which could indicate that in the Netherlands there are only few locations where a project can be realised for this subsidy amount. The subsidy that is needed to realise profitable operations in the majority of the projects has been calculated to amount to 1471 thousand euros per year for a boiler of 10 MW_{th} at 7000 full load hours. The advice on the base rate for 2014 is based on this amount. It is also advised to adjust the correction amount such that it is suitable for large-scale heat supply. With the resulting subsidy, it will be possible to realise heat supply with a boiler fired by solid biomass to replace a gas-fuelled CHP.

Table 25: Boiler fired by solid biomass

Parameter	Unit	Advice 2013	Advice 2014 (< 5 m)	Advice 2014 (5 m)	Total amount for reference
Thermal output capacity	MW_{th_output}	10	0.833	11.1	
Full load hours heat supply	[h/a]	7000	4000	7000	
Investment costs	[€/kW_{th_output}]	425	425	425	€ 0.32 mln resp. € 4,3 mln
Fixed O&M costs	[€/kW_{th_output}]	62	45	62	€34,000/year resp. €620,000
Basis for correction amount		Small-scale	Small-scale	Large-scale	

4.8 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 26 shows the parameters for a boiler fired by liquid biomass.

Table 26: Technical-economic parameters new and existing boilers fired by liquid biomass

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	11,111	
Full load hours heat supply	[h/a]	7000	
Investment cost	[€/kW_{th_output}]	0	€0.0 mln
Fixed O&M costs	[€/kW_{th_output}]	24	€240,000/year
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	39.0	
Fuel price	[€/tonne]	600,0	
Fuel surcharge	[€/tonne]	n.a.	

4.9 Existing installations

4.9.1 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 DNV 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 enable making heat demand more sustainable. Utilisation of latent heat demand need not immediately become appealing.

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, (particularly manure co-digestion plants) and large industrial digesters. On request of the market parties and after consultation with the Dutch Ministry of Economic Affairs, ECN and DNV KEMA have again organised a market consultation for the option of heat utilisation in composting installations. Although new information was provided on the diversity of installations and the feedstock for composting heat, this information has not led to adjustment of the advice.

4.9.2 Expanding heat supply in large incineration and digestion installations

There is a non-measurable difference in costs between expansion of heat in digestion and in incineration.

The costs of heat supply in large projects partly depend on the primary process of incineration or digestion. However, the distinction between heat supply in incineration and heat supply in digestion is not sufficiently visible based on this information. Therefore, ECN and DNV KEMA use one reference project for the expansion of heat supply in large incineration and digestion installations. The reference installation, based on the available potential, is based on heat supply in an existing waste incineration installation. 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 installations have already realised heat and steam supply or are in advanced stages of realising this supply. Both the MEP scheme and the SDE scheme encourage the increasing of efficiency. Therefore, with regard to waste incineration installations, this advice only has bearing on existing waste incineration installations that are not yet subsidised by MEP or SDE and that do not yet supply heat.

Additional heat supply from waste incineration installations involves additional costs, for example for the heat exchangers. The costs of distributing heat or steam are not included in the calculation of the production costs 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 27.

Table 27: Technical-economic parameters heat utilisation in existing projects

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	20	
Full load hours heat supply	[h/a]	7000	
Electricity loss in heat supply		1:4	
Investment cost	[€/kW_{th_output}]	250	€5.0 mln
Fixed O&M costs	[€/kW_{th_output}]	3	€60,000/year
Variable O&M costs (heat)	[€/GJ]	4.30	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

As waste incineration installations 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 installation at the installation's own site. Contrary to a new installation, in case of an existing installation the initiator cannot choose from multiple locations. 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.

Existing agricultural installations such as digesters that use maize instead of manure, have a similar cost structure.

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[4] 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 pipes and additional construction costs. Investment costs are projected at 240 €/kW_{th}. The annual O&M costs have been calculated to amount to 55 €/kW_{th}. The technical-economic parameters are summarised in Table 28.

Table 28: Technical-economic parameters heat utilisation in existing agricultural digesters

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[kW_{th_input}]	350	
Full load hours heat supply	[h/a]	4000	
Investment cost	[€/kW_{th_input}]	240	€ 84,000
Fixed O&M costs	[€/kW_{th_input}]	55	€ 19,000/year
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

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

4 MEP: Environmental Quality of Electricity production OVMEP: Transitional arrangement MEP.

4.9.3 Heat utilisation in composting

Compost heat arises from composting processes. Part of this heat 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. The investment in heat transfer capacity is 450 €/kW_{th}. These and other parameters are listed in Table 30. The resulting production costs are 4.6€/GJ at 7000 full load hours.

Heat utilisation from composting is profitable, unless high investments need to be made to utilise the low-grade heat.

The deployment of heat from composting is complicated by the fact that it is low-value heat. As a result, The number of applications is limited, or additional investments in heat utilisation are needed. The reference is an installation that supplies 7000 full load hours of low-value heat to a buyer who already utilises low-value heat. Under these circumstances, i.e. the heat buyer need not make large investments to utilise the low-value heat, heat utilisation from composting is profitable in the majority of the projects.

Table 29: Technical-economic parameters of heat utilisation in composting (heat)

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	2.0	
Full load hours heat supply	[h/a]	7000	
Investment cost	[€/kW_{th_input}]	450	€ 900,000
Fixed O&M costs	[€/kW_{th_input}]	45	€ 90,000/year
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

4.9.4 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 CHP projects. During the consultation round, extra attention was requested for the renovation costs of a digester. In view of the assumed lifetime of 12 years, ECN and DNV KEMA made calculations on large-scale maintenance to the digestion installation, including the replacement of mixers, gas roof and CHP engine. These costs have been included in the O&M costs. Replacement of the gas engine increases the electrical efficiency. The net efficiency of a renovated digester is lower compared to a newly built installation, given the smaller scale of the MEP digesters.

Table 30: Technical-economic parameters of extended life for digestion (CHP)

Parameter	Unit	Advice 2014 All-feedstock digestion	Advice 2014 Manure co-digestion	Total amount for reference
Input capacity	[MW_{th_input}]	2.2	2.2	
Electrical capacity	[MW_e]	0.8	0.8	
Thermal output capacity	[MW_{th_output}]	0.9	0.9	
Full-load hours electricity supply	[h/a]	8000	8000	
Full load hours heat supply	[h/a]	4000	4000	
Maximum electrical efficiency	[%]	37%	37%	
Investment cost	[€/kW_{th_input}]	0	0	-
Fixed O&M costs	[€/kW_{th_input}]	158	158	€ 0,34 mln
Variable O&M costs (electricity)	[€/kWh_e]	0	-	
Variable O&M costs (heat)	[€/GJ]	-	-	
Energy content fuel	[GJ/tonne]	3.4	3.4	
Fuel price	[€/tonne]	25.0	32.1	
Fuel surcharge	[€/tonne]	n.a.	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 31 shows the technical-economic parameters of production for a green gas or heat hub based on existing all-digesters and manure co-digesters. To expand the lifetime, analogous to the CHP option, the costs of renovation (excluding CHP replacement) have been included in the O&M costs.

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

Parameter	Unit	Advice 2014 (all-digestion heat)	Advice 2014 (all-feedstock digestion green gas)	Advice 2014 Manure co-digestion	Advice 2014 (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 costs (digester)	[€ per Nm^3_{biogas}/h]	-	-	-	-
Investment cost (limited gas cleaning/gas drying)	[€ per Nm^3_{biogas}/h]	385	385	385	385
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	-	-	-	-
Fixed O&M costs (limited gas cleaning/gas drying)	[€/a per Nm^3_{biogas}/h]	38	38	38	38
Energy content substrate	[GJ_{biogas}/tonne]	3	3	3	3
Feedstock cost	[€/tonne]	25	25	32	32
Feedstock price surcharge	[€/tonne]	n.a.	n.a.	1	1

Parameter	Unit	Advice 2014 (all-digestion heat)	Advice 2014 (all-feedstock digestion green gas)	Advice 2014 Manure co-digestion	Advice 2014 (manure co-digestion green gas)
Efficiency gas cleaning	[% methane]	100.0%	100.0%	99.9%	99.9%
Production costs crude biogas	[€ct/Nm^3]/ [€/GJ]	42.5 / 13.4	40.7 / 12.9	50.6 / 16	48.8 / 15.4
Base rate through heat hub (1.1 €/GJ hub and 90% efficiency)	[€/GJ]	16.0		18.8	
Base rate through green gas hub (16.7 €ct/GJ hub and 89.9% efficiency)	[€ct/Nm^3]		61.9		71.0

4.9.5 Extended life of incineration plants

The category for extended life of incineration plants applies to projects whose MEP subsidy has ended, except for biomass co-firing projects. In the coming years, new projects in this category will mainly consist of BECs fuelled by demolition wood and installations using clean wood. The calculation does not include the renovation costs or other costs for the extended life. 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. Recent information shows a reference installation can be characterised as an extended life for a BEC. This implies a change compared to the reference plant used in the draft advice. ECN and DNV KEMA consider further consultation with the market necessary to arrive at advice on a base rate for this category. The advice for the base rate for this category will be drafted in a separate note.

4.10 Hydropower new

The height of fall of the rivers in the Dutch Delta is limited. Existing constructions in rivers are nevertheless suitable for creating sufficient 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 up to 11 meters in exceptional cases. The potential projects in the hydropower category have a wide spreading 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.

For the category hydropower new a reference installation with a height of fall of less than five metres is used. In previous years, the SDE distinguished categories for hydropower with a height of fall of less than five metres and a height of fall of at least five metres. For this advice, a new inventory was made of the projects that are currently being prepared. In establishing the reference installation, the projects with the highest likelihood of applying for SDE in 2014 have been weighed. This has led to an adjustment to the reference installation for hydropower as compared to our advice for 2013. The base rate that has been based on the new reference is higher than 14 €ct/kWh.

Projects with a height of fall of more than five metres are limited to pumping stations near sluices. The combined functionality of water management and energy production, once being realised as a project, will put the project in the hands of Rijkswaterstaat or a water board. No project has been identified that will become eligible for SDE in the hydropower category with a height of fall of more than five metres in the near future.

The technical-economic parameters of the reference installation for hydropower have been summarised in Table 32.

Table 32: Technical-economic parameters hydropower new

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	1.0	
Full load hours	[h/a]	5700	
Investment cost	[€/kW$_e$]	8150	€8.2 mln
Fixed O&M costs	[€/kW$_e$/a]	100	€ 100,000/year
Variable O&M costs	[€/kWh]	-	

4.11 Hydropower renovation

As part of the ‘Programma Rijkswateren 2010 – 2015’, the standards for fish kill that apply to existing hydropower installations are tightened. This means that fish protection measures need to be put in place. For the reference installation of the category hydropower renovation, replacement of the existing turbine with a fish-friendly variant is considered. Compared to the advice of 2013, the parameters in this category remain unaltered.

The main laws and regulations with regard to fish kill near engineering constructions are provided by the EU Water Framework Directive of 2000, the Benelux Decree on Free Fish Migration which was revised in 2009, and the European Eel Regulation. The ‘Programma Rijkswateren 2010-2015” contains an elaboration for the Netherlands for the waters that are managed by Rijkswaterstaat. As part of the management and development plans, some of the existing hydropower installations will need to comply with stricter regulations regarding fish kill. To comply with these regulations, the existing hydropower plants will need to be modified. Integration of an innovative, fish-friendly turbine now seems to be the most important way to comply with the stricter regulations for fish kill.

For the category of hydropower 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 modified as well. It is assumed that the required modifications to the constructions (the engineering constructions) are negligible.

Table 33 shows the technical-economic parameters for the category of hydropower renovation.

Table 33: Technical-economic parameters of fish-friendly renovation of hydropower

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	1.0	
Full load hours	[h/a]	4300	
Investment cost	[€/kW$_e$]	1600	€1.6 mln
Fixed O&M costs	[€/kW$_e$/a]	80	€ 80,000/year
Variable O&M costs	[€/kWh]	-	

4.12 Free tidal current energy

The parameters for this technique have remained unaltered compared to the advice of previous years. This advice was mainly based on inshore free tidal current energy: this involves projects that are realised in or near engineering constructions such as seawalls or semi-permeable dams that use the existing tidal movement. Two permits have been issued for the Oosterscheldekering (Eastern Scheldt storm surge barrier) based on utilisation of tidal energy from free tidal movement. These projects are planned for realisation in 2014 and will supply electricity to the electricity grid. Moreover, permit applications have been submitted for at least two other locations for demonstration projects. It is expected that in the short term contracts will be closed for 25 MW of turbines for projects abroad. This may lead to price decreases for the next series of installations in the Netherlands. Table 34 shows the deployed technical-economic parameters for free tidal current energy.

Table 34: Technical-economic parameters of free tidal current energy

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	1.5	
Full load hours	[h/a]	2800	
Investment cost	[€/kW$_e$]	5100	€7.7 mln
Fixed O&M costs	[€/kW$_e$/a]	155	€ 233,000/year
Variable O&M costs	[€/kWh]	-	

4.13 Osmosis

The potential difference between fresh water and salt water can be used to generate energy (electricity or labour). Two variants of osmosis energy that are in the research and development stage are PRO (Pressure Retarded Osmosis) and RED (Reversed Electrodialysis). In 2013, a small pilot installation of the RED type was realised near the

IJsselmeer dam. The reference installation and the corresponding technical-economic parameters have remained unaltered compared to last year, see Table 35.

Table 35: Technical-economic parameters of osmosis

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	1.0	
Full load hours	[h/a]	8000	
Investment cost	[€/kW$_e$]	36000	€36 mln
Fixed O&M costs	[€/kW$_e$/a]	130	€ 130,000/year
Variable O&M costs	[€/kWh]	-	

4.14 Onshore wind

4.14.1 Wind energy categories

On request of the Dutch Ministry of Economic Affairs, the same category division was maintained for onshore wind energy[5], distinguishing onshore wind, onshore wind with turbines of at least 6 MW and wind in lake.

In the category onshore wind, advice was requested on a cost-effective support which, in the SDE scheme, takes place in the free category. The base rate is fixed and the advice calculates the corresponding number of full load hours that are subsidised to offer adequate support. For the SDE+ 2014, a choice was made to link the stated categories to the wind speeds as indicated in Table 36 below.

Table 36: Subdivision of categories of wind energy and corresponding wind speeds

Category:	Subdivision	Wind speed at 100 meters (m/s)
Onshore wind	Stage I	8.0
Onshore wind	Stage II	7.5
Onshore wind	Stage III	7.0
Onshore wind ≥ 6MW	-	8.0
Wind in lake	-	8.0

4.14.2 Starting points and calculation method

The calculations of the SDE+2014 for wind energy are based on various starting points and assumptions. The resulting technical-economic parameters are included in Table 37. The different parameters are further elaborated in the text below.

5 The SDE+ 2013 was based on this subdivision to implement the resolution of Van der Werf (Parliamentary paper 33 000 XIII, no.68) and Van Tongeren (Parliamentary paper 29023, no. 128).

General principles

The calculations are based on an average wind farm of 15 MW in the three wind speed categories. The category ≥ 6 MW is based on a farm size of 60 MW and wind in lake is based on a farm size of 150 MW.

Table 37: Technical-economic parameters for the various wind categories

Parameter	Unit	Onshore wind	Onshore wind ≥ 6 MW	Wind in lake
Installation size	[MW]	15	60	150
Investment cost	[€/kW$_e$]	1350	1800	2500
Fixed O&M costs	[€/kW$_e$/a]	15.3	15.3	15.3
Variable O&M costs	[€/kWh]	0.0148	0.0148	0.0218

The prices will decrease more slowly compared to 2013.

CAPEX: turbine prices and additional costs

To establish the base rates for the categories for onshore wind energy, various types of wind turbines and corresponding investments have been used (including costs of transport, construction and crane). For 2014, five turbine manufacturers sent price lists. The number of turbines included in the calculations is higher than in the SDE+2013 calculations. Based on the obtained data, it has been observed that the tendency of the 5-10% price decrease in 2013 will not continue next year; instead there will be a minor price decrease.

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). This year, a slight increase in grid connection costs has been detected. The percentage of additional costs for wind turbines has therefore been set at 33%.

On request of the Ministry, calculations have been based on lower feedstock costs of 0.48€/kWh nominal.

OPEX: variable and fixed operational costs

The variable costs consist of guarantee and maintenance contracts and amount to about 1.0 €ct/kWh. The calculations in the category Wind in Lake are based on variable O&M costs of 1.7 €ct/kWh. All categories will have additional soil costs. In the past years, ECN and DNV KEMA considered the RVOB value determined by The Netherlands State Property and Development Agency to be leading in the market. This nominally amounted to 0.53 €ct/kWh. On request of the Dutch Ministry of Economic Affairs, the base rates for 2014 have been calculated based on 10% lower soil costs: 0.48€ct/kWh.

The calculation of the annual fixed costs have included an amount of 15.3€/kW for liability insurance, machine breakage insurance, standstill insurance, cost for maintaining the grid, own use, property tax, and management and soil and road maintenance. These fixed have been kept at the same level as last year. Moreover, for the total maintenance costs, exclusive of soil costs, an inflation rate of 2% per year is used.

Other costs

Additional costs of wind projects such as 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 are not weighed in the calculations made by ECN and DNV KEMA. These additional 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 with the research assignment. These costs are assumed to be earned back through the financial return on equity.

Benefits: gains from turbines
The base rate has been established by combining the above-mentioned costs with the energy output of the wind turbines. These returns are largely determined by the wind resources and the power curve of the wind turbine. The energy output has been calculated for all turbines separately with the help of the specific power curve per wind turbine at annual average wind speeds as indicated in Table 38. The model corrects the wind speed from the table (at a height of 100 meters) for the actual height of axis of the specific turbine. Moreover, the model only makes calculations for the wind turbines which, based on the IEC classification, are actually allowed to be installed for the specific wind speed. Similar to last year, the model also takes into account a 10% output loss, caused by wake losses, non-availability and electrical losses.

The base rate, combined with the corresponding full-load hours, is sufficient for at least 40% of the wind turbine types that are available on the market and suitable for the specific location.

4.14.3 Overview of base rates for wind energy

The resulting base rates and corresponding full load hours are listed in Table 38. For the category onshore wind ≥ 6 MW, by request of the Ministry of Economic Affairs, calculations were also made on the corresponding number of full load hours for a selected base rate of 8.9 and 9.0 €ct./kWh, respectively indicated as Stage II and Stage III.

Table 38: Base rates for onshore wind and wind in lake based on existing categories in SDE+

Category:	full load hours [h/a]	
Onshore wind, Stage I	3500	7.0
Onshore wind , Stage II	2850	8.0
Onshore wind, Stage III	2450	9.0
Onshore wind ≥ 6 MW, Stage II	3700	8.0
Onshore wind ≥ 6 MW, Stage III	3150	9.0
Onshore wind ≥ 6 MW, Stage IV	2900	9.7
Wind in lake	3200	12.3

4.15 Offshore wind

The base rate for offshore wind for farms outside or around the twelve-mile zone is above 15 €ct/kWh. The production costs for wind at sea strongly depend on the location and are calculated assuming an individual connection to the grid, at the expense of the project developer.

The technical-economic parameters for offshore wind are listed in Table 39.

Table 39: Technical-economic parameters offshore wind around or just outside the 12-mile zone

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	300	
Full load hours	[h/a]	3750	
Investment cost	[€/kW$_e$]	3500	€1.05 bln/year
Fixed O&M costs	[€/kW$_e$/a]	100	€30 mln/year
Variable O&M costs	[€/kWh]	-	

4.16 Deep geothermal energy

4.16.1 Introduction

The Dutch Ministry of Economic Affairs asked ECN, DNV KEMA and TNO to find out to what extent large geothermal projects can be realised on the basis of the existing categories for geothermal heat. The first question to be answered is how a large project output can be realised. A larger output can be realised in various ways, i.e. by elevated temperatures and by higher flow rates. In case of a higher temperature, the depth is leading, whereas a higher source flow rate can also be realised through a larger bore diameter of elevated pump pressure. Of course, local geological factors such as the permeability and thickness of the drilled layer are also important.

For the SDE+ 2014 advice on geothermal, ECN, DNV KEMA and THNO have not only looked at projects with large capacities, but also shed a light on the existing category division for geothermal in SDE+ 2013 based on recent experiences with geothermal energy.

4.16.2 Large projects in the SDE+ scheme

In 2013, maximum capacities were implemented for geothermal heat, which are able to prevent over-allotment of SDE+ means. These capacities need to be linked to the level of the reference project: 12.4 MW_{th} in the category up to 2700 metres drilling depth and 10.0 MW_{th} at a minimal drilling depth of 2700 metres. The question of the Ministry was to what extent larger projects (with a higher output) are hindered by this maximum subsidy for output.

Based on the available information on submitted projects in 2012 and 2013, it cannot be ruled out that developers have adjusted original plans for large project capacities into plans with capacities that fit with the maximum capacity that is eligible for subsidy or that a project is submitted in two parts. Capping capacity may have various consequences. One possible consequence is that initiators who want to develop a project with a capacity that exceeds the maximum capacity may be deterred from submitting a subsidy application, as the business case may be negatively influenced by the capping. Another possibility is that the innovative technologies and optimal sustainable heat production are slowed down by the capping when the additional yield, which arises as a result of using an innovation or energy optimisation, is not part of the subsidised capacity.

ECN, DNV KEMA and TNO have been unable to demonstrate that large projects are actually held back by the maximum capacities in the SDE+.

ECN, DNV KEMA and TNO were unable to demonstrate any of these consequences in practise.

Moreover, initiators may be unable to apply for more capacity than the maximum, but this capacity may still be a hardly realistic, high capacity. As a result, and in spite of the capping, there may still be a risk of over-allotment. This could be the consequence of too favourably estimated geological parameters. A geological audit therefore seems desirable.

The capacity of a geological doublet is here defined as follows:

$$Capacity[MW_{th}] = \left(T_{production}[°C] - T_{injection}[°C]\right) \cdot C_{p,water}\left[\frac{kJ}{(kg \cdot K)}\right] \cdot \frac{Flow\ rate[m^3/h]}{3600}$$

This means that there are two options to realise a higher capacity, i.e. via a higher temperature difference (*T*) or a larger depth or more cooling down) and via a higher flow rate (larger bore diameter or higher pump pressure).[6]

If deeper drilling is conducted to realise a higher capacity, it becomes evident that reduced permeability of the soil at larger depths causes the expected capacity to decrease rather than increase in case of depths of 300 to 3500 metres. Creating an artificial reservoir[7], an option in which artificial cracks link the production and injection well directly by means of fracking, has been left out here. This technology is currently not considered commercially viable for this application in the Netherlands. Moreover, the presence of natural cracks has also not been included, as these are very local phenomena and difficult to predict.

6 *C* refers to energy content.

7 The deployment of an artificial reservoir is also referred to as EGS or *Engineered Geothermal System*.

Based on this study, three types of large projects (reference cases) have been identified which may be commercially viable today or in the near future:

- A doublet with a large bore diameter at 2300 m depth.
- A doublet with a large bore diameter at 3000 m depth.
- A doublet at 3500 m depth, including horizontal drilling or fracking.

All calculated reference cases for geothermal heat are represented in Table 40 below. The first reference case is comparable to the majority of the current projects for geothermal heat in the Netherlands. Reference case 2 is based on case 1, however it has a higher capacity because a higher flow rate has been used. This higher flow rate is realised for this case by using a larger pipe diameter, combined with an adjusted pump pressure. Next to increasing the source capacity, this also causes the drilling, well and exploitation costs to rise. The third reference case links up to the final advice for SDE 2013+ and assumes a drilling depth of 3000 metres. The fourth reference case is a combination of a larger bore diameter (with correspondingly higher flow rate) and a larger production depth (3000 metres). The fifth reference case drills at an aquifer depth in which the permeability is still high enough (3500 metres). This drilling has a reasonably large bore diameter and the drilling is done rather diagonally (around 65°) or it is a combination of the diagonal drilling at an angle with mild well stimulation. Reference case 6 assumes that horizontal drilling or fracking is applied to enable the highest possible flow rate.

Table 40: Overview of reference cases for geothermal heat SDE+ 2014

Reference	Drilling depth	Casing diameter*	Reservoir temperature	Flow rate	Capacity
1)	2300 m	5½″	79 °C	150 m^3/h	7 MW_{th}
2)	2300 m	8⅝″	79 °C	325 m^3/h	14 MW_{th}
3)	3000 m	5½″	100 °C	160 m^3/h	11 MW_{th}
4)	3000 m	8⅝″	100 °C	300 m^3/h	20 MW_{th}
5)	3500 m	7⅝″	127 °C	140 m^3/h	14 MW_{th}
6)	3500 m	7⅝″**	127 °C	200 m^3/h	20 MW_{th}

Table notes:

* Casing diameter refers to the outside diameter (in inches) of the casing or liner, on site at the geothermal reservoir.

** Horizontal drilling or fracking is used to increase the flow rate.

4.16.3 Advice on geothermal categories

Studying the (preliminary) results of the SDE+ in 2012 and 2013 and the description of the various reference cases, it becomes evident that the capacity of geothermal heat projects shows a wide dispersion. Moreover, the expected capacity does not have a clear relation with drilling depth. In order to be able to use larger capacities, larger investments will be needed in heat transport pipes as the capacity cannot be deployed at one single location. Production of this larger capacity will require larger investments in the wells as a larger bore diameter will be needed. This leads to higher drilling costs for the following reasons:

- Larger drilling rigs are scarce and increasing demand is pushing up the price.
- Drilling wells with a larger diameter require more energy, material and time.
- More deviated (diagonal) drilling is needed for a sufficiently long breakthrough time of the well: larger drilling distance at the same depth.
- Larger drilling rigs have higher daily costs.
- Larger diameters lead to higher costs for safety measures.
- Increase in drilling risks and hence higher insurance premiums.

All in all, geothermal projects at a depth of about 1500 meters until 3000 meters have more similarities than differences, particularly in view of the base rate. This is based on the assumption that a maximum capacity is not imposed on the various projects.

Category of geothermal low-temperature heat
ECN, DNV KEMA and TNO advise to create a category for geothermal low-temperature, if suitable for the application. This refers to applications that have a heat demand for a temperature of about 70°C to 100°C, as for example in greenhouse horticulture or possibly low temperature district heating for new dwellings. The following features are important for geothermal low-temperature heat:

- A relatively low drilling depth (1500 to 3000 metres) at a temperature level of about 100°C.
- Simultaneous heat supply to multiple greenhouse farms.
- A reference system with 6000 full load hours.

These parameters allow for large project capacities (>20 MW) if wells are drilled with a large bore diameter, but projects with lower capacities are also possible by drilling wells with a smaller diameter and correspondingly lower investment costs.

Category of geothermal high-temperature heat
ECN, DNV KEMA and TNO advise to create a second category for high-temperature heat. Geothermal high-temperature heat means a temperature of more than 120°C. Such a temperature level fits well with existing district heating or a mix if district heating and greenhouse horticulture. Due to the higher costs for deep drilling, it is assumed that the high-temperature projects are only conducted with a minimal temperature gradient of 33.5°C/km (average for the Netherlands). The following features are important for geothermal high-temperature heat:

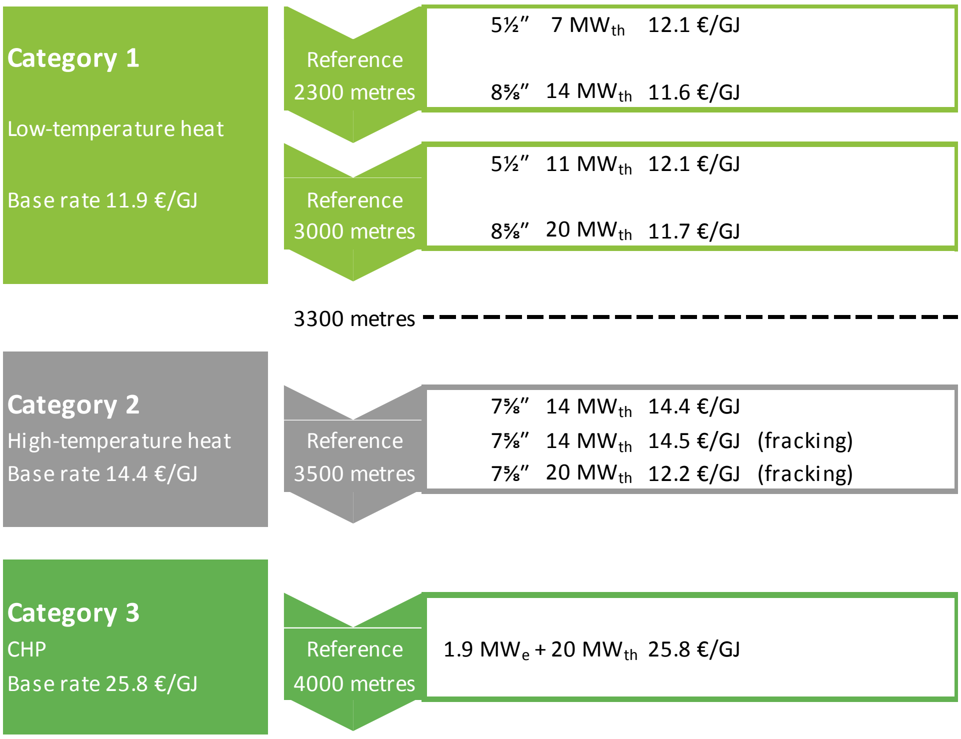
- A relatively large drilling depth (reference 3500 metres) with a temperature level of more than 120°C.
- Heat supply to a mix of district heating and greenhouse horticulture.

- A relatively high number of full load hours of 7000 hours/year or more.
- Horizontal drilling with fracking is required to a higher or lesser extent.

A pragmatic boundary between categories for low and for high temperature can be set at a drilling depth of 3300 metres.

The separation between the two geothermal heat categories needs to be unequivocal and measurable and known prior to the project. Therefore a boundary has been set at 3300 meters drilling depth for production and injection wells. Features such as temperature, flow rate, capacity and investment costs are not (entirely) known beforehand and therefore do not offer a good basis for various categories of geothermal heat. This subdivision is reflected in Figure 3 below. The next sections further discuss the technical-economic parameters for these categories and the corresponding base rates.

Figure 3: Proposal for subdivision of categories for geothermal heat and CHP SDE+ 2014



The third category, '*geothermal CHP*', applies to geothermal projects which, in addition to heat, also produce a significant share of electricity.

Maximum capacity eligible for subsidy or annual heat production

If the amount of production eligible for subsidy per installation for the category of low-temperature heat with a drilling depth of less than 3300 metres is maximised, ECN, DNV KEMA and TNO advise to set the maximum annual production eligible for subsidy at 432,000 GJ, which corresponds with 20 MW_{th} at 6000 full load hours. A lower maximum heat production eligible for subsidy can have a negative impact on the development of large geothermal projects in the Netherlands.

For the category of high-temperature heat, with a drilling depth of more than 3300 metres, it is more difficult to set a limit, which has a low negative impact on the development of new projects. Based on the currently available information on the substrate, it can generally be said that the expected capacity at larger depth will decrease for conventional geothermal (which uses water permeable layers). The reference case with only limited well stimulation at 3500 metres depth yields a capacity of about 14 MW_{th}. If alternative well configurations are applied to such projects, such as long, horizontal sections through the aquifer or well stimulation by means of fracking, the capacity of the doublet may be increased. However, this will require additional investments. In a favourable scenario, this could be an increase to about 20 MW_{th} for the reference installation. The above-mentioned capacities are based on conventional geothermal techniques. In the future, and with the help of alternative development concepts, developments and innovations may be able to further utilise the potential of the deeper underground, as for example with an artificial reservoir (EGS – Engineered Geothermal Systems). In view of their current pre-commercial development stage, these are not yet included as reference case for geothermal heat.

If the amount of production eligible for subsidy per installation for the category of high-temperature heat with a drilling depth of more than 3300 metres is maximised, ECN, DNV KEMA and TNO advise to set the maximum annual production eligible for subsidy at 352,800 GJ, which corresponds with 14 MW_{th} at 7000 full load hours. The additional investments that are needed for horizontal drilling or fracking in reference case 6 can be earned back through revenue from heat supply at market prices for heat for production higher than 352,800 GJ/year. In the calculation of the base rate for case 6, a capping has been included at 14 MW_{th}. Without capping, the base rate would be lower, but apply to the total amount of produced GJ (see Figure 3).

4.16.4 Geothermal low-temperature heat

Greenhouse horticulture will be the main application of geothermal heat with a low temperature in the Netherlands in the near future. Reference cases 1 t to 4, the reference installations, are listed in Table 40. Given the temperature level and capacity, this will most likely involve a small cluster of greenhouse horticulture businesses. An investment in heat transport pipes has been included in the calculation. The number of full load hours is assumed to be 6000 hours per year. The technical-economic parameters for 8 ⅝” and 20 MW_{th} are listed in Table 41. The other scenarios (see Figure 3) calculated for this category show a similar build-up.

Table 41: Technical-economic parameters geothermal low-temperature heat

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	20.4	
Full load hours heat supply	[h/a]	6000	
Investment cost	[€/kW_{th_output}]	1620	€33 million
Fixed O&M costs	[€/kW_{th_output}]	36	€734,000/year
Variable O&M costs (heat)	[€/GJ]	1.01	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

4.16.5 Geothermal high-temperature heat

District heating for existing districts or new housing districts, combined with cascade delivery to greenhouse horticulture, is considered to be the most important application of geothermal heat with a higher temperature. Table 42 shows the technical-economic parameters for the reference installation (7⅝", 14 MW), with a drilling depth of 3500 metres. The investment costs amount to 2230 €/kW_{th}, based on a doublet with a capacity of 14 MW_{th}. The number of full-load hours has been set at 7000 hours/year, which should be feasible in view of the combination of heat buyers with various user profiles. Related to this, an investment in the heat transport pipes has also been included in the calculation.

Table 42: Technical-economic parameters geothermal high-temperature heat

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	13.8	
Full load hours heat supply	[h/a]	7000	
Investment cost	[€/kW_{th_output}]	2230	€ 31 million
Fixed O&M costs	[€/kW_{th_output}]	48	€ 662,000/year
Variable O&M costs (heat)	[€/GJ]	1.62	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

4.16.6 Geothermal CHP

The category of CHP has remained unaltered since the advice for base rates for 2013. ECN, DNV KEMA and TNO plan on evaluating the category for geothermal CHP next year in collaboration with market parties, based on concrete projects that are in the design stage by that time, thus making it possible to establish a more up to date reference installation.

The reference installation of geothermal CHP differs from the other reference installations in terms of characterisation. For geothermal CHP, a reference has been selected which has favourable soil conditions: a temperature gradient of 35°C/km and a flow rate of 200 m^3/hr. The reference drilling depth is 4000 meters. This yields a source capacity for the reference installation of 25.6 MW_{th}. The output capacity is 11.9 MW_{final} (10.0 MW_{th} and 1.9 MW_e), see Table 45. The reference installation (most likely an EGS installation), given the depth and need for fracking, can be considered an innovative project in the sense that no comparable geothermal projects have been realised yet in the Netherlands.

ECN, DNV KEMA and TNO have observed developments that warrant discussions about plans for geothermal CHP and electricity.

Table 45: Technical-economic parameters geothermal high-temperature heat

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	25.6	
Electrical capacity	[MW_e]	1.9	
Thermal output capacity	[MW_{th_output}]	10.0	
Full-load hours electricity supply	[h/a]	5000	
Full-load hours heat supply	[h/a]	4000	
Maximum electrical efficiency	[%]	7%	
Electricity loss in heat supply		-	
Investment cost	[€/kW_{th_input}]	1100	€ 28 million
Fixed O&M costs	[€/kW_{th_input}]	45	€1.2 mln/year
Variable O&M costs (electricity)	[€/kWh_e]	-	
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

It is assumed that heat is delivered to a district heating network at a temperature level of 75°C and that electricity is generated with an Organic Rankine Cycle (ORC). 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 per year.

4.17 Solar PV ≥15 kW_p

The reference plant for solar PV has remained unaltered compared to the final advice of SDE+2013: a roof-integrated system of 100 kW_p is assumed. Based on the research assignment, this advice offers an estimate of the lowest possible costs. It is therefore assumed that a project can be connected to an existing grid connection. The subsidy allocation under SDE+ 2014 requires the applicant to issue orders for the delivery of components of and for the construction of the production installation within one year after the allocation. That is why this calculation assumes the expected price level of 2015.

There is sufficient production capacity outside China at prices that are only slightly higher than the agreed minimum price.

The strong price decrease of solar panels that occurred in 2011 has continued in 2012. In the first half of 2013, there was a slight price increase on the spot market, which was probably the result of an anti-dumping conflict between the EU and Chinese PV manufacturers. Mid-2013, the EU and the Chinese PV manufacturers agreed on a minimum price and a maximum trade volume for solar panels from China. Parties that do not adhere to this agreement will face an anti-dumping import levy. The agreed minimum price can be adjusted based on price developments in the market, allowing the cost price decrease resulting from technological development to continue. Moreover, there appears to be significant production capacity in other countries such as Taiwan, at only slightly higher prices. However, as a result of worldwide overcapacity, there will continue to be a downward pressure on prices.

Due to the strong price decreases in the last years, the margins of many manufacturers are under pressure, including the margins of larger parties. The market is volatile; market shares of manufacturers are still showing much movement and bankruptcies and take-overs are reported regularly. The next years will be important for the PV sector. Businesses will need to strengthen their financial position and tap new sales markets. Prices of other components, such as the converter, and the installation, have also declined in the past years. In view of these developments, it is expected that prices for complete PV systems will further decrease at a moderate pace in the coming years.

Early 2013, low-cost, roof-integrated, turnkey systems with a capacity of about 100 kW_p in the Netherlands had a price level of about 1185 €/kW_p. This amount takes into account the possible capacity decrease. Based on the historic growth curve, a learning effect can be assumed of about 19% per doubling of the worldwide production of solar panels. For the converter a learning effect has been established of 10% per doubling. The price of the other components is assumed to decrease as a result of the increasing efficiency of solar panels. 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 1080 €/kW_p by late 2015, corresponding to a base rate of slightly below 14.7 €ct/kWh[8]. The technical-economic parameters are summarised in Table 44.

Table 44: Technical-economic parameters of solar PV≥ 15 kW_p

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	0.100	
Full load hours	[h/a]	1000	
Investment cost	[€/kW_e]	1080	€ 108,000
Fixed O&M costs	[€/kW_e/a]	-	€1650/year
Variable O&M costs	[€/kWh]	0.0165	

[8] Despite cost declines, this amount is only slightly lower compared to last year's advice. This is due to the fact that the advice for 2014 no longer includes the option to use the Energy Investment Tax Deduction (EIA) in its calculations.

4.18 Solar thermal

In the SDE+ scheme, solar-thermal installations need to comply with a minimum volume requirement of at least 100 m^2 of collector surface area. The Ministry of Economic Affairs has requested another advice for solar-thermal installations with this lower limit of 100 m^2 as starting point. Table 45 provides an overview of the technical-economic parameters.

Investment cost

There is a large difference between investment costs for new constructions and for systems in existing installations, which is caused, among other things, by the complexity of integration into existing installations. The cost data supplied by the market parties show that investment costs for smaller systems (600 to 1200 €/m^2) to systems of about 200 m^2 (300 to 700 €/m^2) are decreasing. This means that clear scale effects are taking place with larger systems. A system of 50 m^2 per surface has 25% higher costs compared to a system of 100 m^2. The price for a system of 100 m^2, as indicated by the market, amounts to 600 €/m^2, which is slightly lower than the investment amount which is currently used for the calculation. Others consider the amount of 700 €/m^2 to be realistic. The costs of a certified measuring system amount to about €1500 to €2000.

Larger solar thermal system s have clear scale benefits

Fixed O&M costs and variable O&M costs (heat)

The amounts listed in the table for maintenance are considered low: maintenance of a 100 m^2 system costs about €900, which is about one to two days of work. This might not be enough for all installations.

Full load hours heat supply

During the market consultation is was remarked that the value for the number of full-load hours depends on the application, particularly the heat demand pattern and the demanded heat temperature level; still a value of 700 hours per year is considered to be a reasonable assumption.

Table 45: Technical-economic parameters of solar thermal

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	0.100	
Full load hours heat supply	[h/a]	700	
Investment cost	[€/kW_{th_output}]	700	€ 70,000
Fixed O&M costs	[€/kW_{th_output}]	5.0	€500/year
Variable O&M costs (heat)	[€/GJ]	3.2	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	n.a.	
Fuel surcharge	[€/tonne]	n.a.	

4.19 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. In the gas cleaning section, impurities are removed 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 is a commercial installation that has passed the small-scale demonstration stage.

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 MWth, 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 46 provides an overview of the technical-economic parameters.

Table 46: Technical-economic parameters biomass gasification

Parameter	Unit	Advice 2014	Total amount for reference
Reference size	[Nm^3/h]	790	
Full load hours	[h/a]	7500	
Internal heat demand	[% gas]	35%	
Internal electricity demand	[kWh/Nm^3]	0.2	
Electricity rate	[€/kWh]	0.10	
Investment costs (digester)	[€ per Nm^3/h]	0	€16.1 million
Investment cost (gas upgrading)	[€ per Nm^3/h]	31400	combined
Fixed O&M costs (digester)	[€/a per Nm^3/h]	0	€138000/year
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	2688	combined
Energy content substrate	[GJ/tonne]	9.0	
Feedstock cost	[€/tonne]	48.0	
Feedstock price surcharge	[€/tonne]	1.0	
Efficiency gas cleaning	[% methane]	100.0%	

5

Overview of base rates

The technical-economic parameters of Chapter 4 and the fuel prices mentioned in Chapter 3 provide the most important data to calculate the base rates, based on the stylised ECN cash flow model that was also used in previous SDE advice. The cash flow model, filled in for each category, can be downloaded from the ECN website via: http://www.ecn.nl.

Here you can also find the other parameters that have not been elaborated in this report. They include the financial assumptions:

- Project financing
- 80% loan capital
- 6% interest on the loan, unless green financing applies (in that case 5%).
- Repayment of the annuity loan.
- 15% return on equity.
- No EIA application (Energy Investment Tax Deduction).
- Corporation tax 25.0%.

One of the financial assumptions is that the Energy Investment Tax Deduction will not be applied.

The resulting base rates are listed in Table 47, Table 48 and Table 49.

Separate advice will be drafted for the base rate of extended lifetime of incineration, because ECN and DNV KEMA consider further market consultation necessary.

Table 47: Overview of advised base rates SDE+ 2014 for biomass digestion in a stand-alone installation

	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
All-feedstock digestion (stand-alone)	*Water*	14.7	[€/GJ]	7000	-
	CHP	26.3	[€/GJ]	8000 / 4000	5739
	Green gas	60.1	[€ct/Nm^3]	8000	-
Manure co-digestion (stand-alone)	*Water*	20.6	[€/GJ]	7000	-
	CHP	31.4	[€/GJ]	8000 / 4000	5732
	Green gas	75.0	[€ct/Nm^3]	8000	-
Manure mono-digestion (stand-alone)	*Water*	27.4	[€/GJ]	7000	-
	Electricity	28.9	[€ct/kWh]	8000	-
	Green gas	104.4	[€ct/Nm^3]	8000	-
WWTP (thermal pressure hydrolysis)	*Electricity*	9.6	[€ct/kWh]	8000	-
WWTP	*CHP*[9]	8.5	[€/GJ]	8000 / 4000	5751
	Green gas	33.3	[€ct/Nm^3]	8000	-
All-feedstock digestion (extended life)	*HP*	24.1	[€/GJ]	8000 / 4000	5855
	Heat (hub)	16.0	[€/GJ]	7000	-
	Green gas (hub)	61.9	[€ct/Nm^3]	8000	-
Agricultural digesters (extended life)	*HP*	28.2	[€/GJ]	8000 / 4000	5855
	Heat (hub)	18.8	[€/GJ]	7000	-
	Green gas (hub)	71.0	[€ct/Nm^3]	8000	-
Heat utilisation existing all-feedstock digestion	*Water*	6.4	[€/GJ]	7000	-
Heat utilisation existing agricultural digesters	*Water*	8.2	[€/GJ]	4000	-
Heat utilisation in composting	*Water*	4.6	[€/GJ]	7000	-

* Note on CHP options: Full load hours electricity/full load hours useful heat utilisation.**Table 48:** Overview of advised base rates SDE+ 2014 for thermal biomass conversion.

[9] Also representative of thermophilic digestion.

	Energy product	Base rate	Unit	Full load hours	Full load hours compiled
Gasification	*Green gas*	129.1	[€ct/Nm^3]	7500	-
Thermal conversion (< 10 MW_e)	*CHP*	40.9	[€/GJ]	8000/4000	4241
Thermal conversion (> 10 MW_e)	*CHP*	22.7	[€/GJ]	7500/7500	7500
Extended life of incineration plants	*CHP*	18.7	[€/GJ]	8000/4000	4429
Boiler fired by solid biomass < 5 MW_{th}	*Water*	14.2	[€/GJ]	4000	-
Boiler fired by solid biomass ≥ 5 MW_{th}	*Water*	11.8	[€/GJ]	7000	
Boiler fired by liquid biomass	*Water*	19.8	[€/GJ]	7000	-
Heat in existing WIPs	*Water*	6.4	[€/GJ]	7000	-
Heat utilisation existing incineration plants	*Water*	6.4	[€/GJ]	7000	-

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

Table 49: Overview of advised base rates SDE+ 2014 for other options

	Energy product	Base rate	Unit	Full load hours*	Full load hours compiled
Geothermal energy and heat					
Deep geothermal (low temperature)	*Water*	11.9	[€/GJ]	6000	-
Deep geothermal (high temperature)	*Water*	14.4	[€/GJ]	7000	-
Deep geothermal energy	*CHP*	25.8	[€/GJ]	5000 / 4000	4158
Wind energy					
Onshore wind (stage I)	*Electricity*	7.0	[€ct/kWh]	3500	-
Onshore wind (stage II)	*Electricity*	8.0	[€ct/kWh]	2850	
Onshore wind (stage III)	*Electricity*	9.0	[€ct/kWh]	2450	
Onshore wind ≥ 6 MW (stage II)	*Electricity*	8.0	[€ct/kWh]	3700	-
Onshore wind ≥ 6 MW (stage II)	*Electricity*	9.0	[€ct/kWh]	3150	-
Onshore wind ≥ 6 MW (stage IV)	*Electricity*	9.7	[€ct/kWh]	2900	-
Wind in lake	*Electricity*	12.3	[€ct/kWh]	3200	-
Offshore wind	*Electricity*	15.7	[€ct/kWh]	3750	-
Hydro energy					
Hydropower new	*Electricity*	16.6	[€ct/kWh]	5700	-
Hydropower renovation	*Electricity*	6.6	[€ct/kWh]	4300	-
Free tidal current energy	*Electricity*	27.6	[€ct/kWh]	2800	-
Osmosis	*Electricity*	54.4	[€ct/kWh]	8000	-
Solar energy					
Solar PV (> 15 kW_p)	*Electricity*	14.7	[€ct/kWh]	1000	-
Solar thermal	*Water*	38.2	[€/GJ]	700	-

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

Abbreviations

BEC	Bio-energy plant
BEMS	Decree on emission regulation mid-sized combustion plants
CAR	Construction all risk, construction insurance
CHP	Combined Heat and Power
COP	Coefficient of performance
EIA	Energy Investment Tax Deduction
EZ	Dutch Ministry of Economic Affairs
LEI	Agricultural Economics Research Institute
MEP	Environmental Quality of Electricity production
MER	Environmental Impact Report
O&M	Operation & Maintenance
ORC	Organic Rankine cycle
SDE	Dutch Renewable Energy Production Support Scheme
SNG	Substitute Natural Gas or Synthetic Natural Gas
VLU	Full load hours
WIP	Waste incineration plant
WWTP	Waste water treatment plant

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