Draft advice base rates SDE+ 2014 for the market consultation

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Acknowledgement

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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 an advice on the subsidy base rates for the feed-in support scheme SDE+. This report contains a draft advice on the cost of projects in the Netherlands targeted for realization in 2014. The options advice covers installation technologies for the production of green gas, biogas, renewable electricity and renewable heat. This draft advice has been written to facilitate the market consultation on the 2014 base rates. The open market consultation is to be held in June 2013.

Contents

Summary

The Dutch ministry of Economic Affairs has asked ECN and DNV KEMA to offer advice on the base rates for 2014. This report contains a draft advice. ECN and DNV KEMA invite market parties to respond to this draft advice.

Table 1 shows an overview of the base rates for thermal conversion of biomass; **Table 2** shows the base rates for biomass digestion and **Table 3** shows the base rates of the other options. For some categories, the calculated base rates exceed 15 €ct/kWh resp. 103.53 €ct/Nm^3, the upper limit in the SDE+. The base rates of these options, i.e. free tidal current energy, new installations for small-scale hydropower, osmosis, green gas from gasification and electricity from manure mono-digestion, have been based on indicative calculations.

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*	123.1	[€ct/Nm^3]	7500	-
Thermal conversion (< 10 MW$_e$)	*CHP*	40.9	[€/GJ]	8000/4000	4241
Thermal conversion (> 10 MW$_e$)	*CHP*	21.8	[€/GJ]	7500/7500	7500
Extended life of incineration plants	*CHP*	18.7	[€/GJ]	8000/4000	4429
Boiler fired by solid biomass	*Heat*	11.5	[€/GJ]	7000	-
Boiler fired by liquid biomass	*Heat*	19.8	[€/GJ]	7000	-
Heat utilisation existing waste incineration plants	*Heat*	6.2	[€/GJ]	7000	-
Heat utilisation existing incineration plants	*Heat*	6.2	[€/GJ]	7000	-

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

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)	*Heat*	14.7	[€/GJ]	7000	-
	CHP	25.9	[€/GJ]	8000 / 4000	5739
	Green gas	59.3	[€ct/Nm^3]	8000	-
Manure co-digestion (stand-alone)	*Heat*	20.6	[€/GJ]	7000	-
	CHP	31.0	[€/GJ]	8000 / 4000	5732
	Green gas	73.9	[€ct/Nm^3]	8000	-
Manure co-digestion (stand-alone)	*Heat*	22.8	[€/GJ]	7000	-
	Electricity	23.5	[€ct/kWh]	8000	-
	Green gas	83.9	[€ct/Nm3]	8000	-
WWTP (thermal pressure hydrolysis)	*Electricity*	9.6	[€ct/kWh]	8000	-
WWTP	*CHP*[1]	6.4	[€/GJ]	8000 / 4000	5751
	Green gas	31.1	[€ct/Nm^3]	8000	-
All-feedstock digestion (extended life)	*HP*	22.5	[€/GJ]	8000 / 4000	5749
	Heat (hub)	14.3	[€/GJ]	7000	-
	Green gas (hub)	56.7	[€ct/Nm^3]	8000	-
Manure co-digestion (extended life)	*HP*	26.4	[€/GJ]	8000 / 4000	5749
	Heat (hub)	17.1	[€/GJ]	7000	-
	Green gas (hub)	65.6	[€ct/Nm^3]	8000	-
Heat utilisation existing all-feedstock digestion	*Heat*	6.2	[€/GJ]	7000	-
Heat utilisation existing manure co-digestion	*Heat*	8.2	[€/GJ]	4000	-
Heat utilisation in composting	*Heat*	4.4	[€/GJ]	7000	-

* 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 energy (500-2700 m)	*Heat*	11.8	[€/GJ]	5500	-
Deep geothermal energy (>2700 m)	*Heat*	12.7	[€/GJ]	5500	-
Deep geothermal energy	*HP*	23.9	[€/GJ]	5000 / 4000	4158
Wind energy					
Onshore wind, extremely rich in wind	*Electricity*	7.0	[€ct/kWh]	3400	-
Onshore wind, very rich in wind	*Electricity*	8.0	[€ct/kWh]	2700	
Onshore wind, rich in wind	*Electricity*	9.0	[€ct/kWh]	2200	
Onshore wind, low-wind	*Electricity*	9.2	[€ct/kWh]	2200	-
Onshore wind ≥ 6 MW	*Electricity*	9.3	[€ct/kWh]	2900	-
Onshore wind ≥ 6 MW (variant 1)	*Electricity*	9.0	[€ct/kWh]	3000	-
Onshore wind ≥ 6 MW (variant 2)	*Electricity*	8.0	[€ct/kWh]	3500	-
Wind in lake	*Electricity*	12.2	[€ct/kWh]	3200	-
Offshore wind (water depth to 10 metres)	*Electricity*	13.5	[€ct/kWh]	3550	-
Offshore wind (water depth 10 metres or deeper)	*Electricity*	about 15	[€ct/kWh]	3730	-
Hydro energy					
Hydropower new	*Electricity*	15.4	[€ct/kWh]	5700	-
Hydropower renovation	*Electricity*	6.2	[€ct/kWh]	4300	-
Free tidal current energy	*Electricity*	25.4	[€ct/kWh]	2800	-
Osmosis	*Electricity*	49.0	[€ct/kWh]	8000	-
Solar energy					
Solar PV (> 15 kW_p) roof-integrated	*Electricity*	13.4	[€ct/kWh]	1000	-
Solar thermal	*Heat*	33.1	[€/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. This report contains the draft advice.

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 electricity 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

This report, the draft advice, was published on 8 May 2013 to serve as input for the public market consultation. A first step in this process was an information meeting on 13 May 2013 for branch organisations, held at the Dutch Ministry of Economic Affairs. This report invites market parties to send their response to this report in writing to ECN. To enable proper weighing in the final advice, these responses need to be submitted together with a verifiable substantiation (contracts, quotations, business cases) and sent to:

Mrs. K. Stutvoet-Mulder
The Energy research Centre of the Netherlands
Unit Policy Studies
Building: 034.236
P.O. Box 1
NL-1755 ZG PETTEN

You can also send your response by e-mail to mulder@ecn.nl.

All responses must have been received by ECN no later than 14 June 2013.

For further information on the content of this report, please contact the project leader, Mr Sander Lensink at telephone number +32 (0)88 515 8219. To make an appointment for a consultation meeting, please contact Mrs Kim Stutvoet-Mulder at telephone number +31 (0)88 515 4554.

After the market consultation, ECN and DNV KEMA will draw up the final advice. ECN and DNV KEMA will respond to each individual response received, orally or in writing. The process, the advice and the way in which ECN and DNV KEMA have weighed the received market responses will also be subjected to an external review which will be conducted on request of the Ministry of Economic Affairs.

3

Prices for electricity and biomass

3.1 Electricity prices

The base rates constitute a measure for the production cost 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 is 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.

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.

Solid biomass is based on pruning and thinning wood as reference fuel

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. This reference 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 about 7 GJ/tonne. However, a large part of the wood delivered to the installations will originate from

stock. Due to natural drying processes of the wood stock, the annual average energy content is assumed to be 9 GJ/tonne. The price range for pruning and thinning wood ranges from 38 to 58 €/tonne. The reference price is assumed to be 48 €/tonne or 5.3 €/GJ. Particularly due the interactions near the border with Germany and Belgium, it may be impossible to obtain pruning and thinning wood for this price throughout the Netherlands. 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 pruning and thinning wood is assumed to have a risk surcharge of 1 €/tonne.

3.2.2 Liquid biomass

Since 2012, the price of vegetable oil is showing a downward trend.

After showing a peak in 2012, the price of vegetable oil is showing a downward trend. In the first quarter of 2013 the price of palm oil was about 15% lower compared to the average price of 2012. The price movements of these oils can be considered leading for the price movements of the reference fuel animal fat. The decrease is now based on the first quarter, whereas the price for the final report will be calculated using the data up to and including the second quarter of 2013. Given the decreasing tendency, the expected average price for 2014 will be lowered by 10% to 600 €/tonne at a heating value of 39 GJ/tonne. The prices of animal fats are moving in line with the prices of vegetable oils. Moreover, there is a well-developed international market for vegetable oils. By trading on the international market for vegetable oils, the risks of rising prices of animal fats can be successfully hedged.

3.2.3 Digestion: Biomass for all-feedstock digesters

In the category all-feedstock digestion a reference 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 the flows themselves 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 is expanded with 80 new products in 2012. The majority of these products is currently exported to digesters abroad. By allowing these co-products, a better linkage is made to regulations for foreign digesters. However, there is a limitation to the allowed 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. However, year after year fluctuations do occur in the market prices of the important co-substrate maize. Figure 1 illustrates the price fluctuations.

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

To prevent the annual fluctuations from having too large an impact on the calculated base rates, the market consultation of 2010 yielded the insight that a long-term average is a more desirable starting point. To correct for fluctuations, the average of the last five years has been calculated based on trade information of the LEI (corrected for transport). The average maize price in the period January 2007 up to June 2012 amounts to 38.5 €/tonne. The final advice will include an average maize price for the period June 2008 till June 2013.

The final advice will include a recalculated average maize price for the period June 2008 till June 2013.

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

Figure 5.2 shows a schematic overview of the assumed feedstock flows in the co-digester.

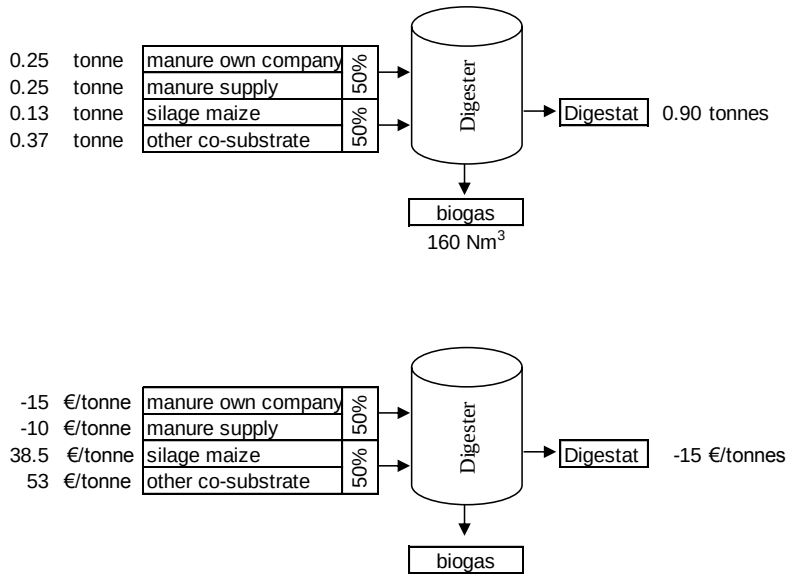

Figure 2: Product flows and prices for digestion inputs and outputs[2]

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. In view of the price developments of energy-rich co-substrates, the average price of co-substrate (excluding maize) in 2012 was indexed with 2% to 7.65 €/GJ or 53 €/tonne at the start of the project, with a net gas yield of 6.9 GJ/tonne. The gas yield of the total input of manure and co-substrate amounts to 3.4 GJ/tonne. In view of price developments during the project, all cost items will be indexed with 2%/year for inflation. This also applies to feedstock costs. Table 5.1 offers an overview of the used prices for 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 Nm3/tonne or GJ/tonne at a certain energy content of the gas (21 MJ/m3). The calculation is based on the energy content of feedstocks in GJ of gas yield per tonne of input. For the sake of completeness: tonnes of input are based on the entire product, not on the dry matter content alone..

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

	Energy content	Price (range)	Reference price
	[GJ/tonne]	[€/tonne]	[€/GJ]
Liquid biomass			
Animal fat	39	600 (550-650)	15.4
Solid biomass			
Pruning and thinning wood	9	48 (38-58)	5.3
Digestion*			
All-feedstock digestion input	3.4	25	7.4
Supply of animal manure	*0.63*	*-10 (-20 to 0)*	*-16*
Removal of animal manure	*0.63*	*-15 (-30 to -5)*	*-24*
Maize	*3.8*	*38.5 (25-45)*	*10.1*
Other co-substrate	*6.9*	*53 (23 to 200)*	*7.65*
Co-digestion input	3.4	32 (14-32)	9.4

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

4

Technical-economic parameters

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

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

4.1 Biomass digestion

4.1.1 Biogas hubs[3]

Introduction

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

[3] ECN and DNV KEMA do not have information about initiatives for new hub installations. As the previously calculated base rates for hub applications are barely different from the base rates calculated for the corresponding autonomous categories, the hub categories can be combined with the corresponding autonomous categories without violating the starting point that the initiatives need to be able to manage financially with the calculated base rates.

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

- Digester.
- Limited gas scrubbing: this step consists mainly of ammonia removal and a deeper hydrogen sulphide-removal than in direct on-site use of the biogas in a CHP installation.
- Heat for the digester: part of the biomass will be used in a boiler to supply the required heat to the digester; it also needs electricity from the grid.
- Gas drying: the biogas must be properly dehydrated prior to transport through crude biogas pipes.
- Transport to an external application: the biogas, consisting mainly of methane and carbon dioxide, is supplied to a different installation where it will be deployed as replacement of natural gas.

Reference systems for production of crude biogas

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

- The cost of CO_2 separation is not included in the calculation[4]..
- The cost of hydrogen sulphide or ammonia removal are discounted in the cost of the digester. Moreover, extra costs are included for additional gas cleaning, gas drying, extra investment for better gas measuring than in CHP applications and a compressor to pump crude biogas to the required pipeline pressure.
- Combustion of part of the crude biogas in a boiler delivers the heat for the digester.
- The electricity for the installation is purchased.

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

Bio-gas pipe

A biogas pipe is needed to transport the crude biogas from the digester to the central hub. The cost of a bio-gas pipe with an estimated length of 10 km and a diameter of 110 mm amounts to approximately 75,000 €/km. This includes a correction for additional costs that need to be made for example for infrastructure crossings.

The costs of the hub includes biogas pipes of a total length of 10 kilometres.

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 5.6 €/GJ. The biogas is converted into heat and power with an annual efficiency of 61% for end use.

[4] The reference installation complies with the emissions standards. The costs of CO_2 separation are not included in this study because these costs need not necessarily be relevant for the production of green gas.

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		n.a.	
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]	0	
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	0	
Fuel surcharge	[€/tonne]	0	
Production costs	[€/GJ]	5.6	

Description of reference heat hub

The technical-economic parameters for the reference heat hub, including biogas pipeline, are illustrated in **Table 6**. These parameters result in a cost price for a heat hub of 1.0 €/GJ. The biogas is converted into heat with an annual 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	
Energy content fuel	[GJ/tonne]	n.a.	
Fuel price	[€/tonne]	0	
Fuel surcharge	[€/tonne]	0	
Production costs	[€/GJ]	1.0	

Description of reference green gas hub

The reference system for a green gas hub has a crude biogas input of 2200 Nm^3/h (or 1300 Nm^3/h of green gas) using gas scrubbing by means of chemicals as gas cleaning

technique. The heat that is needed for this technique is generated by firing part of the crude biogas in a boiler. The needed electricity is purchased.

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

The technical-economic parameters for the reference green gas hub, including biogas 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 16.0 €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 costs	[€/tonne]	0	
Feedstock price surcharge	[€/tonne]	0	
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]	16.0	

It is also possible to feed into a medium pressure grid of a regional distribution grid with a maximum pressure of 8 bar. Combined with gas scrubbing based on chemicals, an extra compressor will need to be installed here, too. Contrary to gas scrubbing with chemicals, cryogenic purification technology functions at a pressure of about 8 bars, allowing the gas to be directly fed into the regional medium pressure grid. Moreover, this technology also has the potential benefit of releasing a flow of pure CO2, which may be commercially tradable. A disadvantage is that this technology is still relatively new; there are no existing plants with gas grid feed-in that have already proven themselves for a number of years. Cryogenic purification is not considered a reference technique, although some experience has been gained in a number of independent installations.

4.1.2 WWTP

For the category of WWTP, ECN and DNV KEMA use two reference installations: the production of renewable energy when replacing an existing gas engine, and expansion

Two references: Replacement of an existing gas engine and increasing the biogas production from thermal pressure hydrolysis.

of the capacity by means of thermal pressure hydrolysis[5]. With these two references, ECN and DNV KEMA aim to describe both the situation of a water treatment plant where previous investments in renewable energy production were made which currently has a need for 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.

Regarding the replacement of the gas engine, it is assumed that this will be done at the location itself: replacing the installation's own CHP by linking to a CHP hub is less obvious due to the high electricity use of the entire treatment plant. An independent installation that fully converts water purification gas into heat is profitable; for comparison check the calculation of a linkage to a heat hub.

Production of green gas after replacing gas engine

The reference system for this category has a crude biogas production of 100 Nm^3/h (or 60 Nm^3/h green gas). This is comparable to a CHP capacity of 200 kW_e. Gas scrubbing is the reference technology for gas cleaning in 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 cost (digester)	[€ per Nm^3_{biogas}/h]	-	€0.6 mln
Investment costs (gas upgrading)	[€ per Nm^3_{biogas}/h]	7515	joint
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	-	€43,000/year
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	506	joint
Energy content substrate	[GJ_{biogas}/tonne]	22	
Feedstock costs	[€/tonne]	-	
Feedstock price surcharge	[€/tonne]	-	
Efficiency gas cleaning	[% methane]	99.9	

The costs for replacing a gas engine are similar to the costs of thermophilic digestion, despite the differences in technique.

Production of renewable energy after replacing gas engine

The reference system for the production of crude biogas and CHP has a thermal input of 570 kW_{th}. This results in an electric capacity of 200 kW_e for CHP. **Tables 9** and **10** show the technical-economic parameters of WWTP for crude biogas and CHP respectively.

[5] 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.

Table 9 Technical-economical parameters for WWTP (crude biogas) The column 'Advice 2014 (other)' refers to the linkage 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]	-	-	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	-	-	
Energy content substrate	[GJ_{biogas}/tonne]	22.0	22.0	
Feedstock costs	[€/tonne]	-	-	
Feedstock price surcharge	[€/tonne]	-	-	
Investment cost (limited gas cleaning/gas drying)	[€ per Nm^3_{biogas}/h]	823	823	€74.000
Fixed O&M costs (limited gas cleaning/gas drying)	[€/a per Nm^3_{biogas}/h]	59	59	€5,300/year
Efficiency gas cleaning	[% methane]	-	-	
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	4.1 / 1.3	3.7 / 1.2	
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	2.4		
Base rate through green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		20.1	

Table 10 Technical-economical parameters for WWTP (CHP)

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	0.571	
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	[%]	35	
Electricity loss in heat supply		-	
Investment cost	[€/kW_{th_input}]	455	€0.3 mln
Fixed O&M costs	[€/kW_{th_input}]	37	€21,000/year
Variable O&M costs (electricity)	[€/kWh_e]	0	
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	22	
Fuel price	[€/tonne]	-	
Fuel surcharge	[€/tonne]	-	

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

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

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

The reference installation of the expansion of the pre-treatment of a WWTP only includes the investment cost in the thermal pressure hydrolysis stage. The costs of dehydration and modification of the existing digestion tank are assumed to be compensated by the lower transportation cost of sludge removal.
The additional gas yield arising from an upstream thermal pressure hydrolysis stage can be deployed in various ways:

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

Due to high heat demand, thermal pressure hydrolysis is a logical combination with a CHP installation

Hydrolysis has its own heat demand. This heat demand can be met by the heat supplied 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/uur]	340	
Calorific value of biogas	[MJ/Nm^3]	25	
CHP capacity (nett)	[kW_e]	723	
Benefit of final processing	[€/tonne of dry matter input]	40	
Total investment	[€/kW_e]	6100	€4.4 mln
Total variable costs	[€/kW_e]	800	€578,000/year

4.1.3 Manure mono-digestion

The Netherlands has a large manure stock. Next to co-digestion of manure for the production of green gas, renewable heat and CHP applications, manure can also be digested without using co-substrate. This application, called manure mono-digestion, meets the criteria of deployment of at least 50% manure and is therefore eligible for the category manure co-digestion. This year, the Ministry of Economic Affairs asked ECN and DNV KEMA to deliver separate advice on the production costs for manure mono-digestion. ECN and DNV KEMA have not learned about any initiatives applying for SDE for manure mono-digestion in the past two years.

ECN and DNV KEMA do not have information on initiatives for manure mono-digestion.

Description of reference installation for production of crude biogas and green gas
The reference system for this category has a crude biogas production of 24.5 Nm^3/h (or 14 Nm^3/h green gas). That is comparable to a CHP capacity of 48 kWe, 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.

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]	24.5	24.5	
Full load hours	[h/a]	7000	8000	
Internal heat demand	[% biogas]	15	15	
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.10	0.10	
Electricity rate	[€/kWh]	0.16	0.16	
Investment costs (digester)	[€ per Nm^3_{biogas}/h]	12450	12450	€0.3 mln jointly
Investment cost	[€ per Nm^3_{biogas}/h]	1175	1175	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	675	675	€19,000/year jointly
Fixed O&M costs	[€/a per Nm^3_{biogas}/h]	118	118	
Energy content substrate	[GJ_{biogas}/tonne]	0.77	0.77	
Feedstock costs	[€/tonne]	-	-	
Feedstock price surcharge	[€/tonne]	-	-	
Efficiency gas cleaning	[% methane]	-	-	
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	69.0 / 21.8	60.7 / 19.2	
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	25.2		
Base rate through CHP hub (5.6 €/GJ hub and 61% efficiency)	[€/GJ]		37.1	
Base rate through green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		83.6	

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]	24.5	
Full load hours	[h/a]	8000	
Internal heat demand	[% biogas]	15	
Internal electricity demand	[kWh/Nm^3_{biogas}]	0.41	
Electricity rate	[€/kWh]	0.10	
Investment costs (digester)	[€ per Nm^3_{biogas}/h]	12450	€0.4 mln jointly
Investment costs (gas upgrading)	[€ per Nm^3_{biogas}/h]	6950	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	675	€24,000/year jointly
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	380	
Energy content substrate	[GJ_{biogas}/tonne]	0.77	
Feedstock costs	[€/tonne]	-	
Feedstock price surcharge	[€/tonne]	-	
Efficiency gas cleaning	[% methane]	99.0	

Description of reference installation for renewable heat and electricity

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

The heat supplied by the CHP plant is entirely needed for the internal digestion process.

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}]	0.149	
Full load hours heat supply	[h/a]	7000	
Internal heat demand	[% biogas]	15	
Internal electricity demand	[kWh/GJ_{output}]	5.41	
Electricity rate	[€/kWh]	0.16	
Investment cost	[€/kW_{th_output}]	2755	€0.3 mln
Fixed O&M costs	[€/kW_{th_output}]	154	€18,000/year
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	0.77	
Fuel price	[€/tonne]	-	
Fuel surcharge	[€/tonne]	-	

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

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	0.149	
Electrical capacity	[MW_e]	0.048	
Thermal output capacity	[MW_{th_output}]	0.031	
Full-load hours electricity supply	[h/a]	8000	
Full load hours heat supply	[h/a]	0	
Maximum electrical efficiency	[%]	32.0	
Electricity loss in heat supply		-	
Investment cost	[€/kW_{th_input}]	2785	€0.4 mln
Fixed O&M costs	[€/kW_{th_input}]	200	€30,000/year
Variable O&M costs (electricity)	[€/kWh_e]	0	
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	0.77	
Fuel price	[€/tonne]	-	
Fuel surcharge	[€/tonne]	-	

4.1.4 Manure co-digestion

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

Initiatives for producing green gas through manure co-digestion or to feed a CHP plant, have been sparse lately.

Description of reference installation for production of crude biogas and green gas
Recent initiatives for manure co-digesters mostly focus on the SDE category for 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.

Additional comments
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.

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
Investment cost	[€ per Nm^3_{biogas}/h]	350	350	jointly
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	280	280	€158,000/year
Fixed O&M costs	[€/a per Nm^3_{biogas}/h]	35	35	jointly
Energy content substrate	[GJ_{biogas}/tonne]	3.4	3.4	
Feedstock costs	[€/tonne]	32	32	
Feedstock price surcharge	[€/tonne]	0.5	0.5	
Efficiency gas cleaning	[% methane]	-	-	
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	59.4 / 18.8	56.5 / 17.9	
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	21.9		

Parameter	Unit	Advice 2014 (heat)	Advice 2014 (other)	Total amount for reference
Base rate through CHP hub (5.6 €/GJ hub and 61% efficiency)	[€/GJ]		34.9	
Base rate through green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		78.9	

Table 16 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 jointly
Investment costs (gas upgrading)	[€ per Nm^3_{biogas}/h]	3020	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	280	€278,000/year jointly
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	300	
Energy content substrate	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	32	
Feedstock price surcharge	[€/tonne]	0.5	
Efficiency gas cleaning	[% methane]	99.9	

Description of reference installation for renewable heat and CHP

Through the years, the composition of the co-substrate has changed, which increased the gas yield per tonne of co-substrate substantially to over 100 Nm^3/tonne of the manure and co-substrate mix.

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})[6]. 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}.

The capacity of heat installations is often higher than the capacity of CHP installations.

[6] As the large majority of the new renewable heat initiatives for this category is smaller than the current reference installation, ECN and KDNV KEMA are inquiring after cost figures of smaller installations to verify if the range of the current reference installation is also still valid for such smaller installations.

For manure co-digestion for renewable heat , an investment cost of 950 €/kWth for crude biogas is assumed, including the cost of an additional boiler. The boiler supplies heat/steam of about 120°C. Costs of a gas pipe or a heat grid have not been included.

Additional comments

The 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 calculated at an electrical efficiency in the conversion of the biogas into net electricity supply amounting to 37%. The feedstock costs of manure co-digestion are volatile due to the dependence on both manure prices and co-substrate costs. Although it is impossible to close long-term contracts to 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}]	3.0	
Full load hours heat supply	[h/a]	7000	
Internal heat demand	[% biogas]	5	
Internal electricity demand	[kWh/GJ_{output}]	5.41	
Electricity rate	[€/kWh]	0.10	
Investment cost	[€/kW_{th_output}]	954	€2.4 mln
Fixed O&M costs	[€/kW_{th_output}]	57	€146,000/year
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	32	
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}]	3.0	
Electrical capacity	[MW_e]	1.1	
Thermal output capacity	[MW_{th_output}]	1.4	
Full-load hours electricity supply	[h/a]	8000	
Full load hours heat supply	[h/a]	4000	
Maximum electrical efficiency	[%]	37.0	
Electricity loss in heat supply		-	
Investment cost	[€/kW_{th_input}]	1150	€3.4 mln
Fixed O&M costs	[€/kW_{th_input}]	85	€253,000/year

Parameter	Unit	Advice 2014	Total amount for reference
Variable O&M costs (electricity)	[€/kWh$_e$]	0	
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	32	
Fuel surcharge	[€/tonne]	0.5	

4.1.5 All-feedstock digestion

Description of reference installation for production of crude biogas and green gas
The reference technology for this category is a digester with various 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. **Table 20** and **Table 21** show the technical-economic parameters for the production of crude biogas or green gas in all-feedstock digesters.

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 jointly
Investment cost	[€ per Nm$^3_{biogas}$/h]	275	275	
Fixed O&M costs (digester)	[€/a per Nm$^3_{biogas}$/h]	220	220	€323,000/year jointly
Fixed O&M costs	[€/a per Nm$^3_{biogas}$/h]	25	25	
Energy content substrate	[GJ$_{biogas}$/tonne]	3.4	3.4	
Feedstock costs	[€/tonne]	25	25	
Feedstock price surcharge	[€/tonne]	0	0	
Efficiency gas cleaning	[% methane]	-	-	
Production costs crude biogas	[€ct/Nm^3] / [€/GJ]	47.6 / 15.0	45.2 / 14.3	
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	17.7		
Base rate through CHP hub (5.6 €/GJ hub and 61% efficiency)	[€/GJ]		29.1	
Base rate through green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		66.4	

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 jointly
Investment costs (gas upgrading)	[€ per Nm^3_{biogas}/h]	2400	
Fixed O&M costs (digester)	[€/a per Nm^3_{biogas}/h]	220	€414,000/year jointly
Fixed O&M costs (gas upgrading)	[€/a per Nm^3_{biogas}/h]	240	
Energy content substrate	[GJ_{biogas}/tonne]	3.4	
Feedstock costs	[€/tonne]	25	
Feedstock price surcharge	[€/tonne]	0	
Efficiency gas cleaning	[% methane]	99.9	

Description of reference installation for renewable heat and CHP

In this digestion option, an existing installation is adjusted such that a heat production or electricity production installation is integrated in the existing installation. The feedstock is mainly supplied by the existing installation and the energy from the produced biogas is mostly supplied back to the same installation as electricity, biogas gas, heat or a combination of these.

New CHP initiatives in all-feedstock digestion installations are smaller compared to the reference installation from previous SDE advice.

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}. The reference installation scale is assumed to be 3 MW_e (8.1 MW_{th_input})[7]. 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**.

[7] As the large majority of the new renewable heat initiatives for this category is smaller than the current reference installation, ECN and KDNV KEMA are inquiring after cost figures of smaller installations to verify if the range of the current reference installation is also still valid for such smaller installations.

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

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	8.1	
Full load hours heat supply	[h/a]	7000	
Internal heat demand	[% biogas]	5	
Internal electricity demand	[kWh/GJ_{output}]	5.41	
Electricity rate	[€/kWh]	0.10	
Investment cost	[€/kW_{th_input}]	586	€4.1 mln
Fixed O&M costs	[€/kW_{th_input}]	32	€222,000/year
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	25	
Fuel surcharge	[€/tonne]	0	

Table 23: Technical-economic parameters manure all-feedstock digestion (CHP)

	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]	0	
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	3.4	
Fuel price	[€/tonne]	25	
Fuel surcharge	[€/tonne]	0	

4.2 Thermal conversion of biomass

In thermal conversion of biomass, excluding gasification for green gas production as discussed in Section 4.15, two system sizes are distinguished, with a boundary value of 10 MW_e.

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 nitric 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.

The reference installation for thermal conversion of biomass (> 10 MW_e) is a back pressure turbine.

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 downgraded given that fresh wood contains significantly less harmful components than B-quality wood.

The technical-economic data of these reference plants have been summarised in **Table 24**.

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

Parameter	Unit	Advice 2014 (small. <10 MW_e)	Advice 2014. (large. 10 MW_e)	Total amount for reference
Input capacity	[MW_{th_input}]	8.7	67	
Electrical capacity	[MW_e]	1.65	10	
Thermal output capacity	[MW_{th_output}]	5.0	50	
Full-load hours electricity supply	[h/a]	8000	7500	
Full load hours heat supply	[h/a]	4000	7500	
Maximum electrical efficiency	[%]	19	14	
Electricity loss in heat supply		1:4	-	
Investment cost	[€/kW_{th_input}]	1550	1840	€13.5 mln resp. €125 mln
Fixed O&M costs	[€/kW_{th_input}]	80	110	€695,000/year resp. €7.5
Variable O&M costs (electricity)	[€/kWh_e]	0.006	0	
Variable O&M costs (heat)	[€/GJ]	0	0	
Energy content fuel	[GJ/tonne]	9	9	
Fuel price	[€/tonne]	48	48	
Fuel surcharge	[€/tonne]	1	1	

4.3 Boiler with solid biomass

The reference installation for this category is a hot water boiler with a combustion grate, using wood from pruning and thinning as reference fuel. In the last two years, there has been an observable tendency of developing small-scale installations between 0.5 and 1 MW_{th}.

In the upcoming market consultation, market parties are invited to address the expected scale size for the coming years. In any case, ECN and DNV KEMA will inquire about the cost figures for boilers smaller than 1 MWth to find out if the range of the current reference installation is also valid in the area below 1 MW_e.

Boilers with a capacity ranging from 0.5 to 1 MW_{th} are increasingly developed

The reference installation has a heat supply capacity of 10 MW_{th}, which, despite the deviation from the average scale size, has a cost level that is representative for installations in the range of 1 to 15 MW_{th}. In the reference installation, the boiler is placed in an existing boiler room in the industry, in horticulture or in a district heating installation. The heat is partly used by industry and partly for space heating. The cost of the distribution system of a heat grid has not been included. Civil works are included in the investment costs. The fixed O&M costs and the investment costs do include a cost item for flue gas cleaning, including a DeNOx. Based on the responses received during

consultation, the investment cost has been raised from 370 €/kW_{th} to 425 €/kW_{th} on output basis. The high investment costs are particularly caused by the higher costs of biomass storage and flue gas cleaning. **Table 25** provides an overview of the technical-economic parameters.

Table 25: Technical-economic parameters of hot-water boiler fired by solid biomass

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	11.1	
Thermal output capacity	[MW_{th_Output}]	10	
Full load hours heat supply	[h/a]	7000	
Investment cost	[€/kW_{th_output}]	425	€4.3 mln
Fixed O&M costs	[€/kW_{th_output}]	62	€620,000/year
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	9	
Fuel price	[€/tonne]	48	
Fuel surcharge	[€/tonne]	1	

4.4 Boiler fired by liquid biomass

The reference fuel is animal fat but the costs are also representative for modification of existing boilers with pyrolysis oil.

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}]	11.1	
Thermal output capacity	[MW_{th_Output}]	10	
Full load hours heat supply	[h/a]	7000	
Investment cost	[€/kW_{th_output}]	0	
Fixed O&M costs	[€/kW_{th_output}]	24	€240,000/year
Variable O&M costs (heat)	[€/GJ]	-	
Energy content fuel	[GJ/tonne]	39	
Fuel price	[€/tonne]	600	
Fuel surcharge	[€/tonne]	0	

4.5 Existing installations

4.5.1 Heat utilisation in existing projects

Existing renewable energy projects often have options for additional heat supply. This heat utilisation is usually not profitable without additional support. ECN and 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.

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

There are significant differences in cost price for heat utilisation in existing projects.

ECN and DNV KEMA expect that a significant potential of renewable heat can be usefully deployed in large incineration plants (particularly waste incineration plants), in relatively small agricultural digesters, (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 will again organise a market consultation for the option of heat utilisation in composting installations.

Expanding heat supply in large incineration and digestion installations

The cost structure of heat supply in large projects partly depends on the primary process of incineration or digestion. This distinction is sufficiently visible in the cost structure, given the distribution of the costs across various projects. Therefore, ECN and DNV KEMA use one reference project for the expansion of heat supply in large incineration and digestion installations. The reference installation, based on the available potential, is based on heat supply in 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 encouraged the increasing of efficiency. Therefore, 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_output}]	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]	4.3	
Energy content fuel	[GJ/tonne]	0	
Fuel price	[€/tonne]	0	
Fuel surcharge	[€/tonne]	0	

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.

For heat supply, an existing agricultural digestion installation is restricted to heat demand in its immediate surroundings, such as at its own premises.

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[8] installations has a capacity that is equal to or larger than 350 kW_e. The calculation is therefore based on an

[8] MEP: Environmental Quality of Electricity production / OVMEP: Transitional arrangement MEP.

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 O&M costs have been calculated to amount to 55 €/kW_{th}/a. The technical-economic parameters are summarised in Table 29.

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

Parameter	Unit	Advice 2014	Total amount for reference
Capacity of heat supply	[$MW_{th\ output}$]	0,350	
Full load hours heat supply	[h/a]	4000	
Investment cost	[€/$kW_{th\ output}$]	240	€84,000
Fixed O&M costs	[€/kWth $_{output}$/a]	55	€19,000/year
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	3,4	
Fuel price	[€/tonne]	0	
Fuel surcharge	[€/tonne]	0	

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

Heat utilisation in composting

Compost heat arises from composting processes. Part of this is needed to maintain the right temperature of the process. The remainder is superfluous and available for useful deployment. To this end, a heat exchanger needs to be installed in the existing air exhaust system. Other costs involve pumps and pipes for heat transport, with an assumed length of 1.5 kilometres. The investment in heat transfer capacity is 450 €/kW_{th}. These and other parameters are listed in **Table 29**. The resulting production costs are 4.4€/GJ at 7000 full-load hours.

The number of full load hours depends on the type of user of the heat

If heat utilisation in composting would mainly result in heat delivery to greenhouse horticulture, the number of full-load hours could be lowered to 5500, similar to the number of full-load hours for geothermal. This would result in a base rate of 5.5€/GJ, with a correction rate based on heat from CHP installations. For now, ECN and DNV KEMA still have insufficient indications to assume that greenhouse horticulture is the most obvious heat consumer.

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

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[$MW_{th\ output}$]	2	
Full load hours heat supply	[h/a]	7000	
Investment cost	[€/$kW_{th\ output}$]	450	€0.9 mln
Fixed O&M costs	[€/$kW_{th\ output}$/a]	45	€90,000/year
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	0	
Fuel price	[€/tonne]	0	
Fuel surcharge	[€/tonne]	0	

4.5.2 Extended life of digestion plants

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

Table 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}]	1.0	1.0	
Full-load hours electricity supply	[h/a]	8000	8000	
Full load hours heat supply	[h/a]	4000	4000	
Maximum electrical efficiency	[%]	37	37	
Electricity loss in heat supply		-	-	
Investment cost	[€/kW_{th_input}]	0	0	
Fixed O&M costs	[€/kW_{th_input}]	148.5	148.5	€321,000/year
Variable O&M costs (electricity)	[€/kWh_e]	0	0	
Variable O&M costs (heat)	[€/GJ]	0	0	
Energy content fuel	[GJ/tonne]	3.4	3.4	
Fuel price	[€/tonne]	25	32	
Fuel surcharge	[€/tonne]	0	0.5	

Digestion plants can also opt for not replacing the gas engine and instead linking the installation to the green gas hub, thus producing green gas instead of electricity. **Table 31** shows the technical-economic parameters of production for a green gas or heat hub based on existing all-digesters and manure co-digesters.

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

Parameter	Unit	Advice 2014 All-feedstock digestion heat	Advice 2014: All-feedstock digestion (green gas)	Advice 2014 Manure co-digestion heat	Advice 2014 Manure co-digestion (green gas)	Total amount for reference
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]	0	0	0	0	€135,000 jointly
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]	290	290	290	290	€121,000/year jointly
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]	3.4	3.4	3.4	3.4	
Feedstock costs	[€/tonne]	25	25	32	32	
Feedstock price surcharge	[€/tonne]	0	0	0.5	0.5	
Efficiency gas cleaning	[% methane]	-	-	-	-	
Production costs crude biogas	[€ct/Nm^3]/ [€/GJ]	37.7 / 11.9	36.6 / 11.6	45.7 / 14.5	44.6 / 14.1	
Base rate through heat hub (1.0 €/GJ hub and 90% efficiency)	[€/GJ]	14.2		17.1		
Base rate through green gas hub (16.0 €ct/Nm^3 hub and 89.9% efficiency)	[€ct/Nm^3]		56.7		65.6	

4.5.3 Extended life of incineration plants

The category for extended life of incineration plants has bearing on projects whose MEP subsidy has ended, except for biomass co-firing projects. The technical-economic parameters of **Table 32** are based on several projects whose MEP allowance has already expired. The fuel price is based on the fuel price for new projects (see Chapter 5).

New projects for extended life will often involve BECs that used to incinerate demolition wood.

In the coming years, new projects in this category will mainly consist of extended life of BECs on demolition wood. The calculation does not include the renovation costs or other costs for the extended life. A fuel switch from B quality wood to pruning and thinning wood for these installations does not relate well to the starting point to not include renovation costs in the calculation. In line with the calculation, it is assumed that the installation remains in operation as long as the variable costs are lower than the revenue. Long-term contracts for fuel therefore need not necessarily be closed, hence a fuel price surcharge does not apply. A heat supply of 4000 full load hours has been used in the calculations. This is lower compared to heat supply in new projects, because existing projects cannot choose a location in the vicinity of suitable heat demand.

Table 32: Technical-economic parameters of extended life for incineration

Parameter	Unit	Advice 2014	Total amount for reference
Input capacity	[MW_{th_input}]	85	
Electrical capacity	[MW_e]	20	
Thermal output capacity	[MW_{th_output}]	50	
Full-load hours electricity supply	[h/a]	8000	
Full load hours heat supply	[h/a]	4000	
Maximum electrical efficiency	[%]	23.5	
Electricity loss in heat supply		1:4	
Investment cost	[€/kW_{th_input}]	0	
Fixed O&M costs	[€/kW_{th_input}]	80	€6.8 mln/year
Variable O&M costs (electricity)	[€/kWh_e]	0	
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	9	
Fuel price	[€/tonne]	45	
Fuel surcharge	[€/tonne]	0	

4.6 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 and up to 11 meters in exceptional cases. The potential projects in the hydropower category have a wide distribution in investment costs and corresponding base rates. Therefore the base rates in this advice are based on specific projects, the realisation potential and the costs playing leading roles in selection.

For the category hydropower new a reference installation with a height of fall of is less than five metres is used. In previous years, the SDE(+) used categories for hydropower with a height of fall of < 5 m and a height of fall of ≥ 5 m. For this advice, a new inventory has been made of projects that are currently under preparation. 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.

The reference installation is calibrated to the next projects for which permits are expected to be issued.

Projects with a height of fall of more than 5 m are limited to pumping stations near sluices. The combined functionality of water management and energy production, once being realised as a project, will lead to the project being managed by Rijkswaterstaat or a water board, Thus, no project has been identified that will shortly become eligible for SDE in the hydropower category with a height of fall of more than 5 m.

The technical-economic parameters of the reference installation for hydropower have been summarised in **Table 33**.

Table 33: Technical-economic parameters hydropower new

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	1.0	
Investment cost	[€/kW$_e$]	8150	€8.2 mln
Full load hours	[h/a]	5700	
Fixed O&M costs	[€/kW$_e$/a]	100	€100,000/year
Variable O&M costs	[€/kWh]	0	

4.7 Hydropower renovation

As part of the 'Programma Rijkswateren 2010 – 2015' (RWS, 2009), 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 turbines by a more 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 from 2000, the Benelux Decree on Free Fish Migration 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 34** shows the technical-economic parameters for the category of hydropower renovation. In view of a changed assumption regarding the interest rate discount for green projects, this year's base rate is slightly higher compared to last year, amounting to 6.3 €ct/kWh.

Table 34: Technical-economic parameters of fish-friendly renovation of hydropower

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	1.0	
Investment cost	[€/kW$_e$]	1600	€1.6 mln
Full load hours	[h/a]	4300	
Fixed O&M costs	[€/kW$_e$/a]	80	€80,000/year
Variable O&M costs	[€/kWh]	0	

4.8 Free tidal current energy

As a result of new projects outside the Netherlands, the costs of free tidal current energy may decrease in the coming years.

The parameters for this technique have not changes compares to the advice of 2012, which was mainly based on the inshore free tidal current energy: this involves projects that are realised in or near constructions such as seawalls or semi-permeable dams that use the existing tidal movement. Two permits have been issued for the Oosterscheldekering (Eastern Scheldt storm surge barrier) based on utilisation of tidal energy from free tidal movement, i.e. Tocardo and IHC Merwede. These projects are planned for realisation in 2014 and will supply electricity to the electricity grid. Moreover, permits 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 35** shows the deployed technical-economic parameters for free tidal current energy.

Table 35: Technical-economic parameters of free tidal current energy

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	1.5	
Investment cost	[€/kW$_e$]	5100	€7.7 mln
Full load hours	[h/a]	2800	
Fixed O&M costs	[€/kW$_e$/a]	155	€233,000/year
Variable O&M costs	[€/kWh]	0	

4.9 Osmosis

The potential difference between fresh water and salt water can be used to generate energy (electricity or labour). There are two types of energy from osmosis that are in the R&D stage:

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

In 2013, Redstack started a small pilot installation of the RED type near the IJsselmeer dam. The reference installation and the technical-economic parameters for osmosis energy, see Table 36, have remained unaltered in the SDE+ advice as compared to last year.

A small pilot installation for osmosis is being realised near the Afsluitdijk.

Table 36: Technical-economic parameters of osmosis

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	1	
Investment cost	[€/kW$_e$]	36000	€36.0 mln
Full load hours	[h/a]	8000	
Fixed O&M costs	[€/kW$_e$/a]	130	€130,000/year
Variable O&M costs	[€/kWh]	0	

4.10 Wind energy

On request of the Ministry of economic Affairs, similar to last year, the following categories are distinguished for wind energy[9]:

1. wind energy at very wind-rich locations
2. wind energy at wind-rich locations
3. wind energy at low-wind locations.
4. wind energy with turbines of 6 MW or higher
5. wind energy with turbines in a lake.
6. wind energy at sea (see Section 4.11).

The decrease in turbine prices of 2013 will continue in 2014 with an additional 5 to 10%.

To establish the base rates for onshore wind energy, various types of wind turbines and corresponding investments have been used. They lead to the conclusion that the price decrease of 2013 will continue in 2014, lowering by 5 to 10% compared to the price level of the previous year.

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). In the calculation these costs have been kept identical to last year's figures in absolute figures. Hence, the percentage of additional costs has risen from 29% to 32% of the turbine costs.

The variable costs, consisting of warranty and maintenance contracts, are projected at about 1.1 €ct/kWh on top of which an inflation of 2% per year is calculated. (NB: an amount of 1.0 €ct/kWh will only be used for the category extremely rich in wind, as the manufacturers of this type of turbines use assume lower maintenance costs. Additional costs for soil are projected at 0.53 €ct/kWh.
The fixed annual costs include 15.3 €/kW for liability insurance, machine breakage insurance, standstill insurance, cost for maintaining the grid, internal use, property tax, superficies allowance, control and soil and road maintenance. These fixed and variable costs have been kept at the same level as last year.

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

The energy yield has been determined by a specific capacity curve per wind turbine and a given yearly average wind speed. The distribution of wind rich categories has been kept the same as last year. For low-wind areas, an average wind speed has been assumed of 7 m/s at 100 metres axis height. Wind-rich areas are set at 7.25 m/s; very wind-rich areas at 7.5 m/s; and extremely wind-rich areas at 8.8 m/s.[10] The selected base rate, combined with the corresponding full-load hours, is sufficient for at least 25%

[9] 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).

[10] The terms 'extremely rich in wind', 'very rich in wind', 'rich in wind' and 'low-wind' are not defined in the research assignment. The research assignment only distinguishes categories that stand out in terms of wind speed.

of the wind turbine types that are available on the market and suitable for the specific locations. Cost-efficiency is thus realised by incentivising sufficient competition among market prices for turbines.

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

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

The technical-economic parameters are listed in **Table 37**, the resulting base rates are included in **Table 38**.

Table 37: Technical-economic parameters wind energy

Parameter	Unit	Advice 2014 (Extremely wind-rich)	Advice 2014 (very wind-rich)	Advice 2014 (wind-rich)	Advice 2014 (low-wind)	Advice 2014 (turbine > 6 MW)	Advice 2014 (wind in lake)
Installation size	[MW]	15	15	15	15	60	150
Investment costs	[€/kW$_e$]	1350	1300	1240	1260	1750	2500
Full load hours	[h/a]	3300	2700	2200	2200	2900	3200
Fixed O&M costs	[€/kW$_e$/a]	15.3	15.3	15.3	15.3	15.3	15.3
Variable O&M costs	[€/kWh]	0.0153	0.0163	0.0163	0.0163	0.0148	0.0223

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

Category:	Full load hours	Base rate
Onshore wind, extremely rich in wind	3400	7.0
Onshore wind, very rich in wind	2700	8.0
Onshore wind, rich in wind	2200	9.0
Onshore wind, low-wind	2200	9.2
Onshore wind ≥ 6 MW	2900	9.3
Onshore wind ≥ 6 MW (variant 1)	3000	9.0
Onshore wind ≥ 6 MW (variant 2)	3500	8.0
Wind in lake	3200	12.2

In the case of onshore wind ≥ 6 MW, 2900 full load hours corresponds to an extremely wind-rich environment. A base rate of 9.0 €ct/kWh for such turbines can be reached at 3100 full load hours. A base rate of 8.0 €ct/kWh corresponds to 3600 full load hours. An SDE+ decision of 8.0 €ct/kWh and maximisation at 3600 full load hours does not lead to overstimulation in case of wind turbines of at least 6 MW according to ECN and DNV KEMA, although 3600 full load hours is no longer realistic in view of the average Dutch wind resources. For wind in lake (and offshore wind) base rates of 11 €ct/kWh or lower are not realistic.

4.11 Offshore wind

In January 2013, a discussion started on the possible lifting of the 2005 moratorium on installing *near-shore* wind farms: Wind farms places inside the twelve-mile zone[11]. The first Dutch offshore wind farm realised, the offshore wind farm Egmond aan Zee (OWEZ), is the only farm within this distance. The second wind farm, the prinses Amalia farm, located 23 km off the coast of Ijmuiden, is slightly outside this zone.

The main reason for putting the development of *near-shore* wind farms on the agenda once again is the anticipated cost benefit resulting from lower water depth, shorter undersea electricity cables and improved reachability for maintenance. As the water depth has a major influence on the height of the investment costs, ECN and DNV KEMA suggest considering two categories for wind at sea, using water depth as a leading criterion, with a suggested water depth boundary of10 meters (at low tide).

The advised base rate for wind at sea at an average water depth below 10 metres is 13.5 €ct/kWh. It should be noted that permits for farms with such water depth have not been issued. Nor have ECN and DNV KEMA made an inventory of the extent to which ecological values raise restrictions for such farms.

The most favourable locations for offshore wind at a water depth of 10 metres or deeper has higher productions costs amounting to about 15 ct/kWh.

The base rate for wind at sea at an average water depth of more than 10 metres amounts to an indicative 15 €/kWh for the most favourable location. The production

[11] The twelve-mile zone is an area at sea within a distance of 12 nautical miles (NM) or sea miles off the coast. A sea mile is defined as 1852 metres; hence 12 sea miles constitute about 22.2 km.

costs for wind at sea strongly depend on the location and are calculated assuming an individual linkage to the grid, at the expense of the project developer.

The technical-economic parameters for both advised categories are indicated in **Table 39** (water depth below 10 metres) and **Table 40** (water depth more than 10 metres).

Table 39: Technical-economic parameters wind at sea, average water depth less than 10 metres

Parameter	Unit	Advice 2013	Advice 2014	Total amount for reference
Installation size	[MW]	-	300	
Investment cost	[€/kW$_e$]	-	3000	€1.05 bln
Full load hours	[h/a]	-	3550	
Fixed O&M costs	[€/kW$_e$/a]	-	100	€30 mln/year
Variable O&M costs	[€/kWh]	-	-	
Base rate	[€/kWh]	-	13.5	

Table 40: Technical-economic parameters wind at sea, average water depth more than 10 metres

Parameter	Unit	Advice 2013 (indicative)	Advice 2014	Total amount for reference
Installation size	[MW]	300	300	
Investment cost	[€/kW$_e$]	4000	3500	€0.90 bln
Full load hours	[h/a]	4000	3730	
Fixed O&M costs	[€/kW$_e$/a]	150	100	€30 mln/year
Variable O&M costs	[€/kWh]	-	-	
Base rate	[€/kWh]	16,0	about 15	

4.12 Deep geothermal energy

Reference installation Geothermal heat

The reference installation for geothermal heat for SDE+ 2013 is based on heat supply to one or multiple greenhouse horticulture businesses. The starting point is a geothermal source (aquifer) at 2300 or 3000 metres depth. At a gradient of 30°C per km, a source temperature of about 80°C will be realised. The geothermal source at 2300 metres consists of a double doublet (two injection and production wells) with a flow rate of 2x138 m^3/hour at a capacity of 12.4 MW$_{th}$. A heat deployment is assumed that equals an ΔT van 40 °C. Heat supply is based on 5500 full load hours. By combining the heat demand of multiple parties, the heat supply can possibly be increased.

The investment cost of the doublet and the above-ground installation amounts to €9.4 million, which equals €1520/kW$_{th}$. The drilling costs take up €6.7 million, including an increase of €1 million as a result of safety margins related to the possible additional

For large projects ECN, DNV KEMA and TNO will issue separate advice.

yield of hydrocarbons and their capturing. The other costs, for instance related to the above-ground installation and pump(s), but also for the guarantee scheme, amount to €2.7 million. The generally longer life of a geothermal source is included in the reference as a residual value of 35% at the end of the SDE+ allowance period of 15 years. The effect on the base rate is comparable to the lowering of the investment cost to 1420 €/kW_{th}, and as such is included in the investment cost.

The fixed O&M costs amount to 2% of the investment cost, equalling 30 €/kW_{th} per year. The variable O&M costs that follow from the required pump energy, based on a COP of 12.5 and electricity costs of 10 €ct/kWh, are 2.2 €/GJ_{heat}. The technical-economic parameters of geothermal heat are summarised in **Table 41**.

Table 41: Technical-economic parameters deep geothermal (heat)

Parameter	Unit	Advice 2014 (500-2700 m)	Advice 2014 (>2700 m)	Total amount for reference
Thermal output capacity	[MW_{th_output}]	12.4	18.0	
Full load hours heat supply	[h/a]	5500	5500	
Investment cost	[€/kW_{th_output}]	1420	1620	€17.6 mln resp. €29.2 mln
Fixed O&M costs	[€/kW_{th_output}]	30	35	€372,000/year resp. €630,000/year
Variable O&M costs (heat)	[€/GJ]	2.2	1.85	
Energy content fuel	[GJ/tonne]	0	0	
Fuel price	[€/tonne]	0	0	
Fuel surcharge	[€/tonne]	0	0	

For large geothermal projects (> 20 MW_{th}) ECN, DNV KEMA and TNO issue separate advice. Large projects, and the influence of capping in the SDE+ scheme on the feasibility of these projects are not part of this report.

Geothermal CHP

The reference plant for geothermal heat is based on a doublet and a depth of the hydrothermal source of 4000 metres. In the variant selected here, very favourable starting points have been selected for two parameters, i.e.:

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

Moreover, the characterisation of the geothermal source in geothermal CHP is by no means an extrapolation of the characteristics of the geothermal source at lower depths as calculated for geothermal heat projects. It is assumed that heat is delivered to a distribution network at a temperature level of 75°C and that electricity is generates with an Organic Rankine Cycle (ORC). The capacity of the geothermal source is 25.6 MW_{th}. The net electrical capacity of the ORC is assumed to be 1.9 MW_e, equalling a net efficiency of over 7%. The number of full load hours for electricity is 5000 hours per year, excluding internal use. The heat capacity for district heating amounts to 10 MW_{th}

which corresponds to a thermal efficiency of 39%. The number of full load hours for heat supply is 4000 hours/year.

Similar to the category for geothermal heat, it is assumed that both the loan and the depreciations involve a period of 15 years. It is assumed that when the SDE+ allowance period of 15 years ends, there will be a residual value of 35%. This has been included in the investment cost. The O&M costs amount to 2% of the investment costs plus the electricity use of the pump(s). The technical-economic parameters are summarised in **Table 42**.

The reference installation for geothermal chp has very favourable conditions for the underground.

Table 42: Technical-economic parameters deep geothermal (CHP)

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	
Full-load hours electricity supply	[h/a]	5000	
Full load hours heat supply	[h/a]	4000	
Maximum electrical efficiency	[%]	7.3	
Electricity loss in heat supply		0	
Investment cost	[€/kW_{th_input}]	1100	€28.2 mln
Fixed O&M costs	[€/kW_{th_input}]	45	€1.15 mln/year
Variable O&M costs (electricity)	[€/kWh_e]	0	
Variable O&M costs (heat)	[€/GJ]	0	
Energy content fuel	[GJ/tonne]	0	
Fuel price	[€/tonne]	0	
Fuel surcharge	[€/tonne]	0	

4.13 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 from 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.

The price decrease of solar panels in 2011 continued in 2012.

The price decrease of solar panels that occurred in 2011 has continued in 2012. It is expected that prices will continue to decrease at a moderate pace in the coming years, while there is some uncertainty about the short term. There is currently some price uncertainty in the market due to an investigation issued by the EU with regard to the dumping of panels from China. Based on the outcome of this investigation, the Chinese panels may be retroactively taxed with import duties. The exact height of these duties is

This draft advice does not take into account a price increase resulting from import duties.

not yet know right now. This uncertainty has already resulted in moderate price increases in the last months. Due to the high uncertainty, this draft advice cannot include any structural price increases resulting from the import duties. More information may be available when the final advice is published.[12] Due to the strong price decreases in the last years, the margins of many manufacturers are under pressure, as well as the margins of larger parties. The market is volatile; market shares of manufacturers are showing much movement and bankruptcies and take-overs are reported regularly. The next years will be important and decisive for the PV sector. Businesses will need to strengthen their financial position and tap new sales markets.

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 deterioration in time. Based on the historic growth curve, a learning effect can be assumed of about 19% per doubling of the worldwide production 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 1075 €/kWp by late 2015, corresponding to a decrease in the base rate to 15.0 €ct/kWh compared to the advice of last year.. The technical-economic parameters are summarised in **Table 43**.

Table 43: Technical-economic parameters of solar PV≥ 15 kW_p

Parameter	Unit	Advice 2014	Total amount for reference
Installation size	[MW]	0.1	
Investment cost	[€/kW_e]	1075	€108,000
Full load hours	[h/a]	1000	
Fixed O&M costs	[€/kW_e/a]	-	
Variable O&M costs	[€/kWh]	0.017	

4.14 Solar thermal

In the SDE+ scheme, solar-thermal installations need to comply with a minimum 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. The technical-economic parameters have not changed compared to the previous advice, see **Table 44**.

[12] If the study should give sufficient reason for it, the Committee may decide to impose a preliminary levy in July 2013. The final results of the study are expected late 2013.

Table 44: Technical-economic parameters of solar thermal

Parameter	Unit	Advice 2014	Total amount for reference
Thermal output capacity	[MW_{th_output}]	0.1	
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]	1.6	
Energy content fuel	[GJ/tonne]	0	
Fuel price	[€/tonne]	0	
Fuel surcharge	[€/tonne]	0	

4.15 Biomass gasification

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

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

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/nl/units/ps/themas/hernieuwbare-energie/projecten/sde/.

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.
- EIA is applied based on the EIA list of 2013 (at 44% deduction).
- Corporation tax 25.0%.

The resulting base rates are listed in **Table 46, Table 47** and **Table 48.**

Table 46: 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)	*Heat*	14.7	[€/GJ]	7000	-
	HP	25.9	[€/GJ]	8000 / 4000	5739
	Green gas	59.3	[€ct/Nm^3]	8000	-
Manure co-digestion (stand-alone)	*Heat*	20.6	[€/GJ]	7000	-
	HP	31.0	[€/GJ]	8000 / 4000	5732
	Green gas	73.9	[€ct/Nm^3]	8000	-
Manure co-digestion (stand-alone)	*Heat*	22.8	[€/GJ]	7000	-
	Electricity	23.5	[€ct/kWh]	8000	-
	Green gas	83.9	[€ct/Nm^3]	8000	-
WWTP (thermal pressure hydrolysis)	*Electricity*	9.6	[€ct/kWh]	8000	-
WWTP	*CHP*[13]	6.4	[€/GJ]	8000 / 4000	5751
	Green gas	31.1	[€ct/Nm^3]	8000	-
All-feedstock digestion (extended life)	*WKK*	22.5	[€/GJ]	8000 / 4000	5749
	Heat (hub)	14.3	[€/GJ]	7000	-
	Green gas (hub)	56.7	[€ct/Nm^3]	8000	-
Manure co-digestion (extended life)	*WKK*	26.4	[€/GJ]	8000 / 4000	5749
	Heat (hub)	17.1	[€/GJ]	7000	-
	Green gas (hub)	65.6	[€ct/Nm^3]	8000	-
Heat utilisation existing all-feedstock digestion	*Heat*	6.2	[€/GJ]	7000	-
Heat utilisation existing manure co-digestion	*Heat*	8.2	[€/GJ]	4000	-
Heat utilisation in composting	*Heat*	4.4	[€/GJ]	7000	-

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

Table 47: 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*	123.1	[€ct/Nm^3]	7500	-
Thermal conversion (< 10 MW_e)	*WKK*	40.9	[€/GJ]	8000/4000	4241
Thermal conversion (> 10 MW_e)	*WKK*	21.8	[€/GJ]	7500/7500	7500
Extended life of incineration plants	*WKK*	18.7	[€/GJ]	8000/4000	4429
Boiler fired by solid biomass	*Heat*	11.5	[€/GJ]	7000	-
Boiler fired by liquid biomass	*Heat*	19.8	[€/GJ]	7000	-
Heat utilisation existing waste incineration plants	*Heat*	6.2	[€/GJ]	7000	-
Heat utilisation existing incineration plants	*Heat*	6.2	[€/GJ]	7000	-

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

Also[13] Also representative of thermophilic digestion.

Table 48: 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 energy (500-2700 m)	*Heat*	11.8	[€/GJ]	5500	-
Deep geothermal energy (>2700 m)	*Heat*	12.7	[€/GJ]	5500	-
Deep geothermal energy	*WKK*	23.9	[€/GJ]	5000 / 4000	4158
Wind energy					
Onshore wind, extremely rich in wind	*Electricity*	7.0	[€ct/kWh]	3400	-
Onshore wind, very rich in wind	*Electricity*	8.0	[€ct/kWh]	2700	
Onshore wind, rich in wind	*Electricity*	9.0	[€ct/kWh]	2200	
Onshore wind, low-wind	*Electricity*	9.2	[€ct/kWh]	2200	-
Onshore wind ≥ 6 MW	*Electricity*	9.3	[€ct/kWh]	2900	-
Onshore wind ≥ 6 MW (variant 1)	*Electricity*	9.0	[€ct/kWh]	3000	-
Onshore wind ≥ 6 MW (variant 2)	*Electricity*	8.0	[€ct/kWh]	3500	-
Wind in lake	*Electricity*	12.2	[€ct/kWh]	3200	-
Offshore wind (water depth to 10 metres)	*Electricity*	13.5	[€ct/kWh]	3550	-
Offshore wind (water depth 10 metres or deeper)	*Electricity*	about 15	[€ct/kWh]	3730	-
Hydro energy					
Hydropower new	*Electricity*	15.4	[€ct/kWh]	5700	-
Hydropower renovation	*Electricity*	6.2	[€ct/kWh]	4300	-
Free tidal current energy	*Electricity*	25.4	[€ct/kWh]	2800	-
Osmosis	*Electricity*	49.0	[€ct/kWh]	8000	-
Solar energy					
Solar PV (> 15 kW_p) roof-integrated	*Electricity*	13.4	[€ct/kWh]	1000	-
Solar thermal	*Heat*	33.1	[€/GJ]	700	-

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

Abbreviations

AVI	Waste incineration installation
BEC	Bio-energy plant
BEMS	Decree on emission regulation mid-sized combustion plants
CAR	*Construction all risk*, construction insurance
COP	*Coefficient of performance*
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 Support Scheme
SNG	*Substitute Natural Gas or Synthetic Natural Gas*
VLU	Full load hours
CHP	Combined Heat and Power

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