Renewable Energy Sources Act (EEG)

Progress Report 2007

Bundesministerium
für Umwelt, Naturschutz
und Reaktorsicherheit

Renewable Energy Sources Act (EEG)
Progress Report 2007

pursuant to Article 20 of the Act

to be submitted to the German Bundestag

by

**the Federal Ministry for the Environment,
Nature Conservation and Nuclear Safety (BMU)**

in agreement with

the Federal Ministry of Food, Agriculture and Consumer Protection

and

the Federal Ministry of Economics and Technology

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1 Summary

Legal mandate and background:

In view of the dynamic expansion of renewable energies (RE), regular monitoring of the existing support instruments is required, which if necessary should result in the adaptation of the current legal provisions to de facto developments. The Renewable Energy Sources Act (*Erneuerbare-Energien-Gesetz* – EEG) is an important and successful instrument to promote renewable energies; as a result of the Act, the development of renewable energies in the electricity sector is particularly dynamic. Pursuant to Article 20 of the Renewable Energy Sources Act (EEG) of 21 July 2004, the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) shall, in agreement with the Federal Ministry of Food, Agriculture and Consumer Protection (BMELV) and the Federal Ministry of Economics and Technology (BMWi), submit a progress report to the Bundestag on the Renewable Energy Sources Act by 31 December 2007 and subsequently every four years thereafter.

The present Progress Report describes not only the political parameters but also the progress achieved with renewables expansion, and the impacts of the Act itself. As well as addressing cross-sectoral aspects, it describes developments in the individual sectors and formulates policy recommendations on that basis, taking particular account of electricity production cost trends over recent years and desirable developments for the future. With the implementation of these policy recommendations as part of the forthcoming revision of the Renewable Energy Sources Act and through flanking measures outside the scope of the Act itself, the aim is to further optimise the expansion of renewable energies in the electricity sector.

The target set in the current Renewable Energy Sources Act is to increase the share of renewable energies in total electricity generation to at least 12.5% by 2010, with a minimum target of 20% for 2020. These targets must now be reviewed. The Act's revision must also take account of the European Council's decision in spring 2007, under the German Presidency, to set a binding target of a 20% share of renewable energies in overall EU energy consumption (electricity, heating and cooling, fuels) by 2020.

Development of renewable energies: Target for 2010 already reached

Since the Renewable Energy Sources Act entered into force in 2000, the share of renewables in primary energy consumption has more than doubled, from 2.6% in 2000 to around 5.8% in 2006; the same applies to the share of renewables in total final energy consumption, from 3.8% (2000) to around 8.0% (2006). The share of renewable energies in total gross electricity consumption has almost doubled, from 6.3% in 2000 to around 11.6% in 2006. A figure above 13% is forecast for 2007, which means that the expansion target set in the Renewable Energy Sources Act for 2010 will be exceeded as early as 2007.

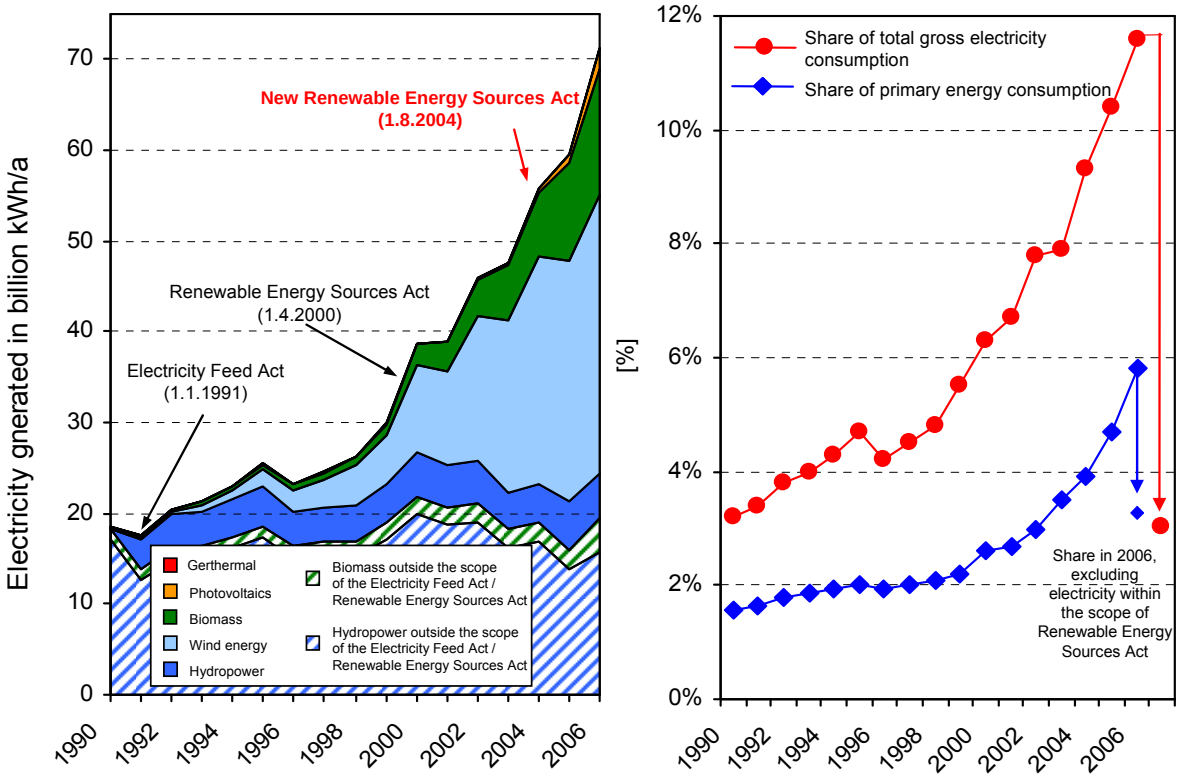


Fig. 1-1: Development of electricity production from renewable energies and their contribution to gross electricity consumption and primary energy consumption for the period 1990-2006 (calculated on the basis of the physical energy content method) [1]

In 2006, wind energy accounted for the largest share of renewables' contribution to gross electricity consumption with around 30.7 billion kWh, i.e. around 5%, followed by hydropower, which remained stable at around 20.7 billion kWh. Electricity generation from biomass (including biogenic waste) showed a strong upward trend, rising from around 8.0 billion kWh in 2004 to around 15.6 billion kWh in 2006, i.e. approximately 2.5% of gross electricity consumption. Electricity generation from photovoltaics increased almost fourfold from 0.6 billion kWh in 2004 to around 2.2 billion kWh in 2006, i.e. around 0.4% of gross electricity generation.

Table 1-1: Development of electricity generation from renewable energies and mine gas in 2006 which is remunerated under the Renewable Energy Sources Act (provisional data, in some cases estimated) [1, 2, 3, 4]

	Number of installed plants	Installed capacity (new construction 2006)	Electricity generated under the EEG (change against 2004)	CO_2 reduction[7]	Remuneration paid under the EEG (change against 2004)	Volume of investment	Jobs, including areas falling outside the scope of the EEG
		[MW]	[in billion kWh]	[million t]	[€ million/a]	[€ billions]	
Hydropower (Article 6 EEG)	7,524 [1]	4,700 (+ 20)	4.924[2] (+6.7%)	22.522	366.6 (+8.6%)	0.07	9,400[8]
Landfill gas, sewage treatment plant gas, mine gas (Article 7 EEG)	770	598	2.789 (+7.7%)	3.303	195.6 (+7.4%)		
of which sewage treatment plant gas	290 [4]	123 [4]	0.270 (+1.1%)	0.966			
of which landfill gas	330 [4]	250 [4]	1.050 (+/- 0)	1.143			
of which mine gas	150	225 (-2) [5]	1.469 (+33.5%)	(1.194)			
Biomass (Article 8 EEG)	5,262	2,331 (+598.4)	10.9[3] (+108%)	12.796	1,337.4 (+163%)	1.35	64,000
of which solid biomass	162	1,094 (+76)	5.42[3] (+66.8%)	8.309			52,600
of which biogas	3,300	1,000 (+335)	4.17 (+208.7%)	3.412			10,600
of which liquid biomass	1,800	237 (+177.4)	1.314 (+1,606%)	1.075			800
Geothermal energy (Article 9 EEG)	1	0.2 (0)	0.0004	0	0.05		Approx. 50
Wind energy (Article 10 EEG)	18,685	20,622 (+2,224)	30.71 (+20.4%)	26.47	2,733.8 (+18.3%)	2.9	82,100
of which repowering		286.8 [6] (+140)					
of which offshore	0	0	0	0			
Photovoltaics (Article 11 EEG)	approx. 200,000	2,831 (+950)	2.220 (+298.6%)	1.516	1,176.8 (+316%)	4.28	26,900
of which free-standing	171	187.6 (+74.6)					

[1] plus approx. 155 plants producing electricity which is not remunerated under the EEG
[2] plus around 15,749 billion kWh of electricity generated from hydropower which is not remunerated under the EEG
[3] plus around 3.6 billion kWh of electricity from the biogenic share of waste and 1.1 billion kWh of electricity from other plants which is not remunerated under the EEG
[4] 2005 figures; more recent data not available
[5] In 2006, total installed capacity decreased for the first time.
[6] As recorded for the period 2003-2006.
[7] including electricity generated from renewables which is not remunerated under the EEG
[8] including jobs in those parts of the hydropower sector not receiving remuneration under the EEG

Impacts of the Renewable Energy Sources Act (EEG)

Environmental impacts

In 2006, carbon dioxide (CO_2) emissions were reduced by around 44 million tonnes through the promotion of renewables in the electricity sector (2005: 38 million tonnes of CO_2). No other instrument (e.g. the Act on Combined Heat and Power Generation, emissions trading, the ecological tax reform, the Market Incentive Programme for Renewable Energies, etc.) has resulted in similar CO_2 reductions.

The expansion of renewable energies also makes a contribution to nature conservation. Since 2004, the Act has contained specific provisions to ensure that the expansion of renewables is compatible with nature conservation. This Progress Report therefore also contains an environmental assessment of each of the renewable energy sectors to determine their impacts on nature and landscape.

Economic impacts

The Renewable Energy Sources Act continues to generate considerable impetus for innovation, domestic value added and employment. According to a recent analysis, domestic turnover from the installation and operation of renewable energy systems increased from € 18.1 billion in 2005 to around € 22.9 billion in 2006, with around € 14.2 billion of this being directly attributable to the Renewable Energy Sources Act. Exports will become increasingly important in future: in 2006, for example, the export share of the German wind energy sector was already above 70%, while that of the photovoltaics sector was around 30%.

This has been accompanied by a substantial increase in employment in the renewables industry. The number of people employed in all the renewable energy sectors rose from 160,000 in 2004 to around 236,000 in 2006. Around 134,000 of these jobs, i.e. almost 60%, were created as a result of the Renewable Energy Sources Act. In parallel to these positive employment effects, however, the renewables expansion has also had some negative impacts on jobs. From an economic perspective, this is due to the budget effect: the additional costs of promoting renewables under the Act at present reduce consumers' purchasing power and, as a knock-on effect, lead to lower demand for goods and therefore job losses in other sectors. However, it should be noted in this context that the overall balance is positive: there has been a net gain in employment, even taking into account the negative employment effects of renewables expansion. According to recent studies, the net employment effect in 2006 amounted to between 67,000 and 78,000 jobs [3].

Of these 134,000 jobs resulting from the Renewable Energy Sources Act, wind energy accounted for the major share, i.e. around 82,000 jobs, followed by photovoltaics with 27,000, 22,000 in bioenergy power generation, and around 3,000 in hydropower [3].

Other effects of the Renewable Energy Sources Act (EEG) are significant savings due to avoided energy imports (hard coal and gas imports for electricity generation), and, with conventional power being substituted by electricity from renewables, avoidance of environmental damage from CO_2 emissions and hence its resulting external costs.

Table 1-2: Contribution of renewable energy sources to electricity generation in Germany 1990 – 2006 [2, 4]

	Hydropower [1)]	Wind energy	Biomass [2)]	Biogenic waste fraction [3)]	Photovoltaics	Geothermal	Total electricity generation
	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]
1990	17,000	40	222	1,200	1	0	**18,463**
1991	15,900	140	250	1,200	2	0	**17,492**
1992	18,600	230	295	1,250	3	0	**20,378**
1993	19,000	670	370	1,200	6	0	**21,246**
1994	20,200	940	570	1,300	8	0	**23,018**
1995	21,600	1,800	670	1,350	11	0	**25,431**
1996	18,800	2,200	853	1,350	16	0	**23,219**
1997	19,000	3,000	1,079	1,400	26	0	**24,505**
1998	19,000	4,489	1,642	1,750	32	0	**26,913**
1999	21,300	5,528	1,791	1,850	42	0	**30,511**
2000	24,936	7,550	2,279	1,850	64	0	**36,679**
2001	23,383	10,509	3,206	1,859	116	0	**39,073**
2002	23,824	15,786	4,017	1,945	188	0	**45,760**
2003	20,350	18,859	6,970	2,162	313	0	**48,654**
2004	21,000	25,509	8,347	2,116	557	0.2	**57,529**
2005	21,524	27,229	10,495	3,039	1,282	0.2	**63,569**
2006	20,673	30,710	13,987	3,639	2,220	0.4	**71,230**

1) In the case of pumped storage power plants, electricity generated from natural inflow only

2) Until 1998, only feed-in to the general supply grid; includes electricity generation from sewage treatment plant and landfill gas

3) Share of biogenic waste in incineration plants estimated at 50%

Without the support provided under the Renewable Energy Sources Act, renewable energies are still not price-competitive with conventional electricity generation, whereby wind power is closest to being competitive. Plant operators therefore continue to be reliant on the fees paid under the Act. The differential costs, among other things, are of relevance when evaluating the economic impact of the Act. These costs – amounting to around € 3.3 billion in 2006 – are the additional costs resulting from the total fee payments for renewable-generated electricity (€ 5.8 billion in 2006) as compared with energy supply companies' avoided costs of purchasing the conventional electricity that would have been required without the feed-in of electricity from renewable sources under the Act (€ 2.5 billion in 2006). The resultant surcharge payable for renewable-generated electricity was € 0.7 ct/kWh, which amounts to less than 4% of the average price of domestic electricity. The Renewable Energy Sources Act was responsible for around 13% of the electricity price increases for households in the period 2002-2006.

Table 1-3: Development of installed capacity for electricity generation from renewable energies, 1990 – 2006 [2, 4]

	Hydropower	Wind energy	Biomass[1)]	Photovoltaics	Geothermal	Total installed capacity
	[MW]	[MW]	[MW]	[MW_p]	[MW]	[MW]
1990	4,403	56	190	2	0	**4,651**
1991	4,403	98	No data	3	0	**4,504**
1992	4,374	167	227	6	0	**4,774**
1993	4,520	310	No data	9	0	**4,839**
1994	4,529	605	276	12	0	**5,422**
1995	4,521	1,094	No data	16	0	**5,631**
1996	4,563	1,547	358	24	0	**6,492**
1997	4,578	2,082	400	36	0	**7,096**
1998	4,601	2,875	409	45	0	**7,930**
1999	4,547	4,444	604	58	0	**9,653**
2000	4,572	6,112	664	100	0	**11,448**
2001	4,600	8,754	790	178	0	**14,322**
2002	4,620	11,965	952	258	0	**17,795**
2003	4,640	14,609	1,137	408	0	**20,794**
2004	4,660	16,629	1,550	1,018	0.2	**23,857**
2005	4,680	18,428	2,192	1,881	0.2	**27,181**
2006	4,700	20,622	2,740	2,831	0.2	**30,893**

The figures on installed capacity refer to the year-end status in each case – cumulative

1) Includes total installed capacity from sewage treatment plant and landfill gas plants

Besides the differential costs, various other costs arise as well, including the costs of control and balance energy, transmission system operators' transaction costs, and the additional costs of upgrading the grid, especially to accommodate regionally concentrated wind energy generation, and in future, the costs of connecting offshore wind farms to the electricity transmission grid.

Cross-sectoral aspects: Better grid integration

Due to the desired and expected further rapid expansion of renewables in the electricity sector, it is important to ensure that the total share of electricity from renewable energy sources can continue to be fed reliably into a secure transmission grid, and to facilitate maximum possible feed-in of electricity from renewable energy systems. Various recommendations are made in this Progress Report to reflect these considerations. For example, targeted feed-in management should be introduced so that in the event of grid bottlenecks occurring, only the power flow from those renewable energy plants which are causing the current grid problem is regulated. In order to achieve this, the grid system operator should be able to regulate by remote control all RE plants with a capacity of more than 100 kW. A hardship scheme should be considered for affected renewable energy plant operators. Besides better grid management, grid reinforcement and expansion by grid system operators, plant operators should also make a contribution to grid stability in future: through the delivery of system services at wind energy plants and the use of virtual power plants, load management and energy storage systems. The Progress Report therefore makes recommendations for a new approach to feed-in management and system integration.

It is also recommended that the principle of exclusive use of renewables be elaborated and made more flexible so that in future, electricity generated from a mix of renewable sources can be remunerated under the EEG without any problems. However, as at present, no fees should be payable under the Act for the generation of electricity from a mix of renewable and non-renewable sources in future.

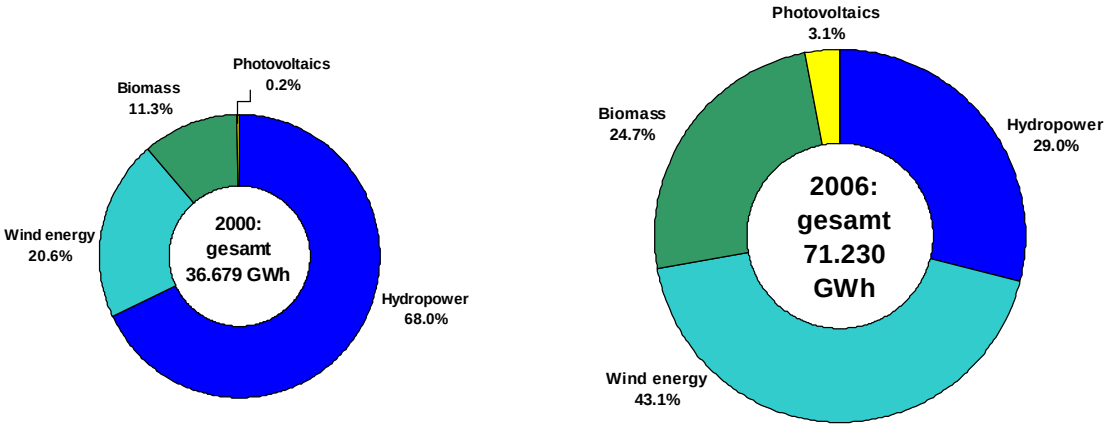


Fig. 1-2: Electricity generated from renewable energies: individual sectors' shares of total energy production in 2000 and 2006 [1]

Special equalisation scheme for energy-intensive companies

The special equalisation scheme established under Article 16 of the Renewable Energy Sources Act relieves much of the burden on particularly energy-intensive manufacturing companies and rail operators in the purchase of electricity paid for under the Act. Since entering into force in 2003, this Article has been amended on several occasions and the number of beneficiaries substantially increased, most recently at the end of 2006 with the first Act to amend the Renewable Energy Sources Act (01.12.2006). In 2006, a total of 327 companies, including 45 rail operators, benefited from these provisions, with € 420 million being apportioned under the equalisation scheme, which has generally proved its worth.

As part of the forthcoming revision of the Act, minor adjustments are proposed in relation to the application and processing procedures with the aim of improving the administration of the equalisation scheme. Further modifications should be considered in a review based on the experience gained during the first few years following the entry into force of the first amending Act (01.12.2006).

Hydropower: Harnessing existing potential

As the energy potential of hydropower has already been exploited to a relatively high degree, market trends have remained fairly stable in recent years. The contribution made by hydropower to electricity generation has stagnated at around 3.5% of Germany's gross electricity consumption. In recent years, a small amount of capacity has been added through new construction, reactivation and repowering, resulting in an additional 20 MW per year. The establishment of plants with a capacity of more than 5 MW is viewed positively, and three major projects have been initiated here. This will impact on installed capacity in the next two to three years and will result in an additional 0.7 billion kWh/p.a. of electricity generated from hydropower.

As investments in improving ecological status are generally not economically viable in the new construction of small-scale plants under the existing remuneration system, an increase

in the remuneration rates from the present level of 9.67 ct/kWh to as much as 12.67 ct/kWh is recommended here. Moreover, the criteria relating to the improvement of ecological status should in future apply to hydropower plants in all capacity categories. For systems with a capacity of over 5 MW, abolition of the upper capacity limit, the cut-off date and the requirement for modernisation to result in an increase in the electrical energy of at least 15% is recommended. The remuneration period for hydropower plants should be 20 years, in line with the other renewables sectors.

Landfill gas, sewage gas, mine gas: Market largely saturated

The landfill and sewage treatment plant gas market and the mine gas market are well-developed in Germany. The inclusion of mine gas in the Renewable Energy Sources Act in 2000 triggered dynamic market development, but here too, increasing market saturation can be observed since 2005. In order to harness the remaining potential for power generation from landfill and mine gas, the remuneration rate for small-scale plants should be increased, while the rates of remuneration payable to large-scale mine gas plants should be reduced.

Biomass: A booming industry creating value in rural regions

Electricity from biomass (excluding landfill and sewage treatment plant gas) remunerated under the Renewable Energy Sources Act has shown dynamic growth since the new Act entered into force in 2004. Electricity generation has increased from 5.2 billion kWh in 2004 to around 10.9 billion kWh in 2006. This is due primarily to the strong increase in biogas systems, whose total electricity output almost quadrupled between 2004 and 2006 to 1000 MW_{el}. The main reason for this was the introduction of a bonus for the use of cultivated biomass (NawaRo bonus), which is currently claimed by around 60% of all biogas plants. The development of electricity generation from solid biomass, on the other hand, has been relatively stable since 2000, with total installed capacity of 1,100 MW_{el} at the end of 2006. Due to the incentive effects of the NawaRo, technology and CHP bonuses, there is a noticeable trend towards small- and medium-capacity plants up to and including 500 kW_{el}.

There has been a sharp increase in the installed capacity of small-scale cogeneration units which run on vegetable oil, from 12 MW_{el} in mid 2004 to 237 MW_{el} by the end of 2006. The smaller units generally run on rapeseed oil, while larger facilities are fuelled with palm oil. It is calculated that 340,000 tonnes of palm oil per annum are required to run the capacity installed at the end of 2006. In light of the fact that natural areas, including tropical forests, are being cleared to create palm oil plantations, this trend is viewed critically in terms of its environmental impacts. In order to counteract the growing use of biomass from non-sustainable sources, it is recommended that palm oil and soya oil be excluded from the NawaRo bonus scheme until an effective certification scheme to safeguard their sustainable cultivation is in place.

The Federal Government will also lobby at European level for the establishment of sustainability criteria for cultivated biomass. At the same time, the basis for authorisation should be introduced in the EEG for an ordinance to be enacted which defines the sustainability criteria for the cultivation of renewables.

Deficits can still be noted in the use of slurry and the utilisation of waste heat from biogas plants. Many opportunities to exploit the energy potential of these two areas still remain untapped.

It is recommended that the remuneration rates for plants with a capacity below 150 MW_{el} be increased by 1 ct/kWh. The NawaRo bonus for electricity generated from biogas (existing and new plants) with a capacity up to and including 500 MW_{el} should be increased by 1 ct to 7 ct/kWh, with a further 1 ct increase for electricity generated from biogas (existing and new

plants) with a capacity up to 150 MW_{el} if at least at least 30% farm manure is used (percentage based on volume or mass). Furthermore, dry fermentation should be excluded from the technology bonus.

In order to provide more effective incentives for the utilisation of waste heat, it is recommended that the bonus for combined heat and power production (CHP bonus) be increased by 1 ct to 3 ct/kWh. It is also recommended that the NawaRo bonus for electricity generated by the burning of wood from landscape cultivation or short-rotation plantations be increased from 2.5 ct/kWh to 4 ct/kWh.
The annual degression in the remuneration rates for new plants, amounting to 1.5%, should be reduced slightly to 1% p.a. All bonuses in the biomass sector should be subject to degression of 1% p.a. from 2010.

Finally, the principle of exclusive use should be made more flexible for biogas plants using cultivated biomass: it should be possible for specific plant by-products which are not eligible for the NawaRo bonus to be used in conjunction with NawaRo biomass in future. This should be based on a positive list. However, the entitlement to the NawaRo bonus should apply solely to the replenishable share of inputs used to generate electricity from biogas.

Geothermal: Further support required for market development

There is still only one plant generating electricity from deep geothermal energy in operation in Germany, namely in Neustadt-Glewe (Mecklenburg-Western Pomerania). However, two other geothermal power plants – in Unterhaching and Landau – are close to completion. Around a dozen projects in the Upper Rhine valley and the Molasse Basin in Southern Germany have reached various stages in the development process. The interest in harnessing the substantial potential afforded by geothermal energy, which is entirely viable if the overall parameters are in place, is evident from the fact that by the end of 2006, 150 exploration licences had already been issued, 125 of them in Bavaria and Baden-Württemberg. The electricity production costs depend to a very substantial extent on the physical conditions on the ground. Furthermore, drilling costs in particular have increased substantially in recent years due to the strong increase in exploration activities in the oil and gas industries. The projects currently in development can only be implemented with additional research funding.

The Progress Report recommends a reduction in the number of capacity categories to just two, i.e. up to and including 10 MW_{el} and over 10 MW_{el}. The basic fee should be increased to 16 ct/kWh for capacities up to 10 MW_{el} and to 10.5 ct/kWh for capacities above 10 MW_{el}. It also recommends the introduction of a heat cogeneration bonus of 2 ct/kWh and a technology bonus of 2 ct/kWh for non-hydrothermal systems (e.g. Hot Dry Rock).

The creation of a fund to cover the exploration risk is also recommended, with special drilling risks to be partially covered by investment subsidies tied to certain conditions (and not exceeding 30% of the total drilling costs) through the Market Incentive Programme (MAP). The Progress Report also recommends increasing R&D funding.

Wind energy: Giving incentives for grid stabilisation and for onshore repowering, safeguarding the breakthrough offshore

Wind energy made by far the largest contribution to total gross electricity production from renewable energies in 2006 with 30.7 billion kWh. At the end of 2006, a total of 18,685 wind energy plants were in operation in Germany, with an installed capacity of 20,622 MW. However, a decrease in the installation of new wind turbines has been noted in recent years which can be attributed primarily to the limited availability of new sites. For that reason, repowering will in future be especially important for any further expansion of capacity; however, initial progress here has been very slow. The further expansion of onshore wind energy and repowering are severely impeded at present by administrative hurdles.

The Progress Report recommends providing greater incentives for repowering by reducing the requisite capacity increase from threefold to twofold (with a maximum limit of a fivefold increase) and making the rules applicable to all plants which have been in operation for more than 10 years. The Progress Report also recommends ensuring that enough suitable sites are made available for repowering and that development is not impeded by overzealous rules on spacing and height restrictions.

In view of the substantial increase in installed capacity in the onshore wind energy sector in recent years and the aim of continuing this development, it is essential that wind farms, too, contribute to grid stabilisation in future. The Progress Report therefore recommends that certain features of wind farms which can help enhance grid stability be made mandatory for all wind farms in future. It is important to determine whether, as a quid pro quo, the remuneration rate should be increased accordingly. The annual rate of degression should be set at a value between 1 and 2% p.a.

There is also major potential to harness offshore wind energy. In all, 18 licences for offshore wind farms, with a total capacity of 6,200 MW, have been granted to date in the area of Germany's exclusive economic zone in the North and Baltic Sea. As yet, however, none of the projects has been implemented. This is due in part to the lengthy licensing procedures for cable routes, but economic factors also play a role. The level of remuneration currently payable under the Renewable Energy Sources Act is judged to be inadequate for the majority of the planned projects.

From an ecological perspective, a special positive effect is that the provisions excluding wind farms from marine protected areas are proving effective, with no further applications having been lodged or licences granted for these areas.

For offshore wind farms, it is recommended that the remuneration rate for the first 12 years be increased from 8.74 to 11-15 ct/kWh, with a reduction in the rate of final fees from 5.95 to 3.5 ct/kWh. The option of postponing the start of degression to 1 January 2013, instead of 1 January 2008, and raising the rate of degression to 5–7% should also be considered.

Photovoltaics: Continuing the expansion of a major international industry, harnessing the potential for further cost cuts

The photovoltaic sector has undergone a period of booming expansion since 2004: with around 2,800 MW_p in 2006, total installed capacity has increased sevenfold compared with 2003. Due to this strong growth, Germany has become the world's most important market for photovoltaic systems, and more than € 1 billion has been invested in new production capacity along all stages of the value chain. Regions in East Germany continue to benefit particularly from this development. Exports are also developing positively, although the share of exports in photovoltaics is relatively low – around 30% – compared with other industrial

sectors and there is clearly scope for expansion. Germany's photovoltaic production plant construction is now a world leader and German solar cell manufacturers were also able to increase their world market share very rapidly to more than 20% as early as 2005, despite rapidly expanding total volume in this segment.

Electricity production costs in the photovoltaics sector decreased by around 60% between 1991 and 2003, with the period 1999-2003 alone accounting for a drop of 25 percentage points. This also shows that the high rate of growth in photovoltaics has resulted in a decrease in manufacturing costs for photovoltaic modules. Due to the strong demand overhang and the intermittent shortage of silicon, however, these were not reflected in corresponding price cuts. Nonetheless, financial calculations show that the fees payable under the Renewable Energy Sources Act generally allow optimised photovoltaic systems to operate economically and, with favourable framework conditions, higher profits can be achieved than calculated.

From an environmental perspective, the provisions on free-standing photovoltaic systems have proved their worth. However, the share of free-standing capacity currently stands at below 10%. Although around 50% of the areas used for this purpose are cropland, no adverse environmental impacts can be observed as these are extensively used sites which can also evolve into valuable wildlife habitats, e.g. for birds.

The Progress Report recommends a 1ct/kWh reduction in the basic rate of remuneration from 1.1.2009 for all photovoltaic systems. The degression for roof-mounted systems should be progressively increased from the current rate of 5% to 7% p. a. from 2009 and to 8% p. a. from 2011. For free-standing systems, the rate of degression should be increased from 6.5% at present to initially 7% (from 2009) and to 8% p. a. from 2011. The introduction of a new category for roof systems with a capacity of over 1000 kW_p and a reduction in the remuneration rate to 34.48 ct/kWh from 2009 is also recommended.

Further prospects: Continued expansion – more ambitious targets

The previous target – to increase the share of renewable energies in electricity generation to at least 12.5% by 2010 – will be exceeded as early as 2007 with an estimated figure of at least 13%. Furthermore, the EU's binding target of a 20% share of renewable energies in overall EU energy consumption (electricity, heating and cooling, fuels) by 2020 means that the national expansion targets must also be adapted accordingly. Current scenarios indicate that renewable energies can feasibly make a 25-30% contribution to gross electricity consumption in Germany by 2020.

Germany's national expansion targets for renewables should be adapted in line with the decisions taken at Meseberg on 23-24 August 2007. At its closed meeting in Meseberg, the Federal Cabinet agreed a future expansion target of 25-30% for renewable energies by 2020, to replace the current target of "at least 20%", with continued steady expansion after 2020. In the medium term, this increase will lead to a corresponding rise in differential costs.

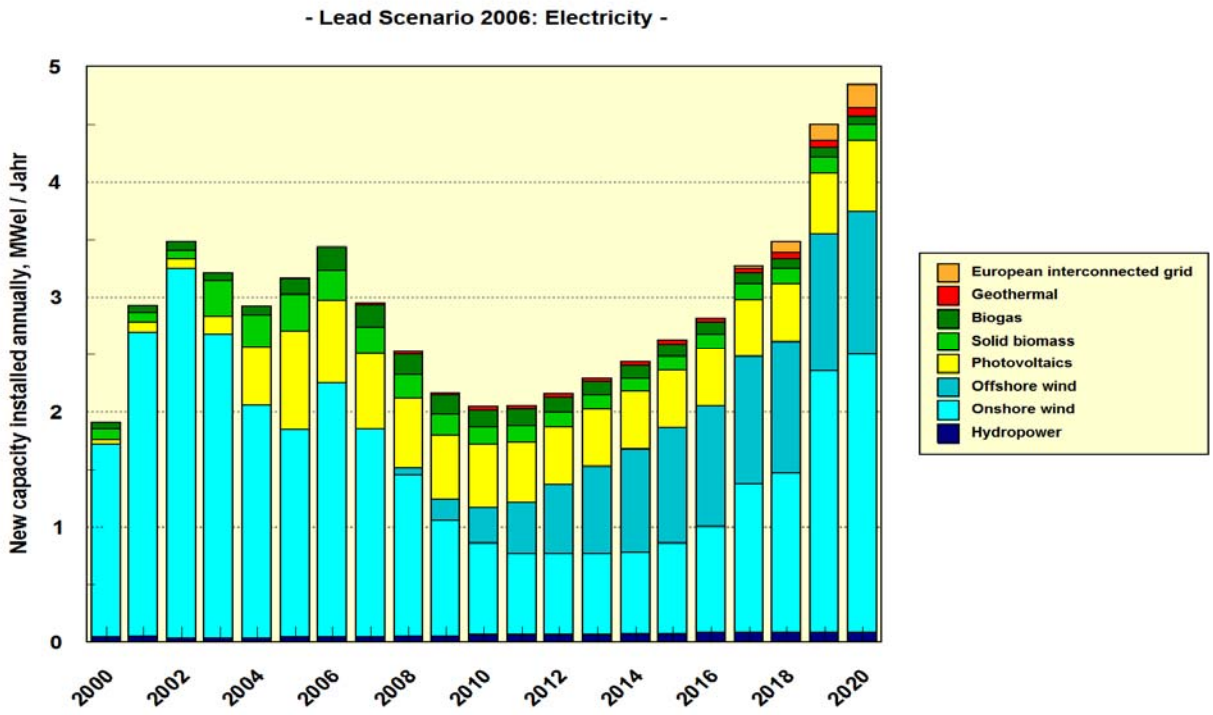


Fig. 1-3: **Trends in new capacity installed annually for electricity generation from renewable energies for the period 2000-2020, based on the Lead Study prepared by the DLR Institute for Technical Thermodynamics [5]**

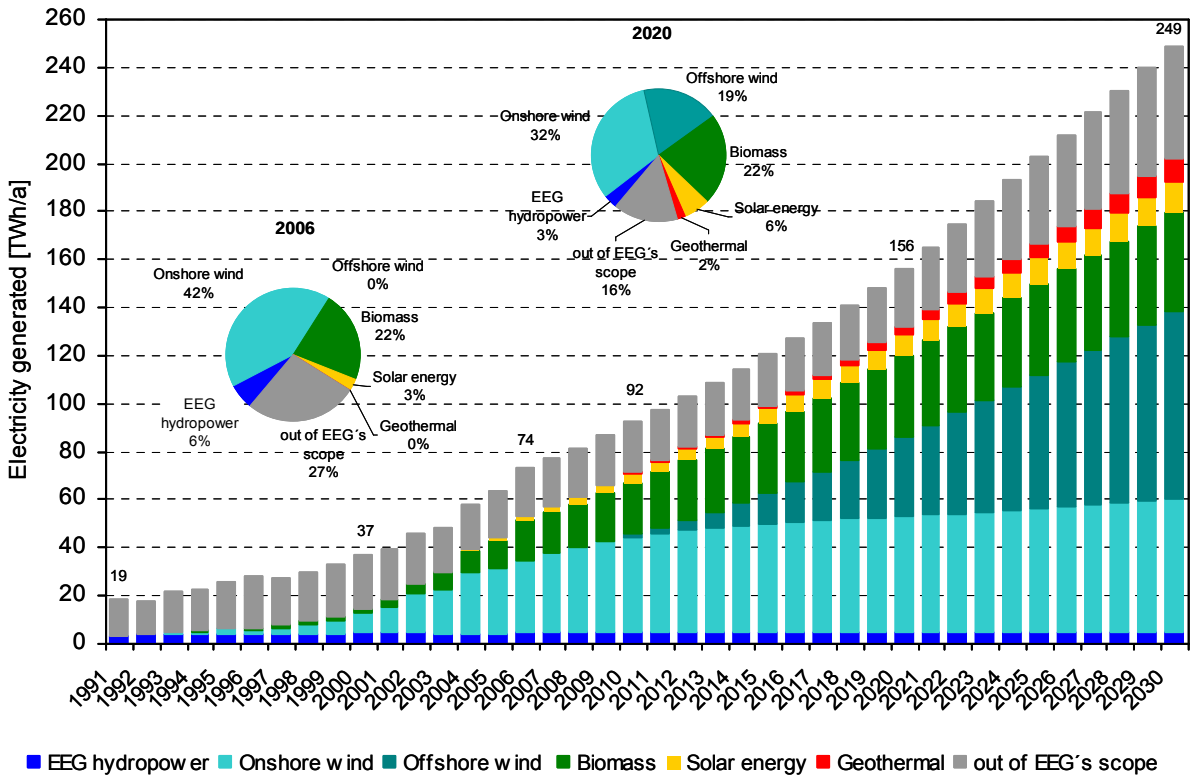


Fig. 1-4: **Trends in electricity generation from renewable energies 1991-2030, based on the Lead Study prepared by the DLR Institute for Technical Thermodynamics [5]**

Key policy recommendations for the revision of the Renewable Energy Sources Act (EEG)

	Provisions within the scope of the Renewable Energy Sources Act Overview (effective as of 1.1.2009)	Flanking measures Overview
Cross-sectoral	• A uniform remuneration period of 20 years for all RE sectors • The principle of exclusive use to be elaborated, making payment of fees for electricity generated from a mix of renewable sources more straightforward • Clarification of the prohibition of multiple sale • Feed-in management to involve the use of all economically viable opportunities for grid optimisation using best available technologies • Mandatory use of technologically optimised feed-in management with the aim of safeguarding grid security at the lowest possible cost and maximum possible feed-in from RE plants • Obligation of RE plant operators to ensure that their systems can be regulated by remote control by the grid operator in the event of grid bottlenecks • Introduction of an appropriate hardship scheme for RE plant operators to be considered • Administration of the special equalisation scheme for energy-intensive enterprises to be improved	
Hydropower	• Amendment of fee categories; an increase in the fees paid for plants with a capacity up to and including 5 MW, especially new plants • For systems with a capacity of over 5 MW: abolition of the cut-off date, the upper limit of 150 MW and the requirement for modernisation to result in an increase in the electrical energy of at least 15% • Appropriate modification of remuneration rates due to changed remuneration period	• Development of a strategy to introduce an inter-plant remuneration system for the ecological modernisation of several plants within a single river basin district • Simplification of approval procedure under water law • Remuneration under the Act to be based on clear criteria laid out in the Renewable Energy Sources Act (EEG), Federal Water Act (WHG) and the Environmental Code (UGB)
Landfill gas, sewage gas and mine gas	• Increase in the remuneration rate for landfill gas plants with a capacity up to and including 500 kW_{el} • Reduction in fees for mine gas plants with a capacity above 1 MW_{el} • Amendment of capacity categories for mine gas plants to 0-1 MW_{el}, 1-5 MW_{el} and >5 MW_{el} Adaptation of remuneration rates as follows: capacity up to and including 1 MW_{el}: 7.16 ct/kWh (currently 7.16 / 6.16 ct/kWh)	

	Provisions within the scope of the Renewable Energy Sources Act Overview (effective as of 1.1.2009)	Flanking measures Overview
Biomass	• Increase of 1 ct/kWh in basic rate of remuneration for new and existing facilities with a capacity up to and including 150 kW_{el} • Increase from 6 to 7 ct/kWh in NawaRo bonus for electricity from biomass (new and existing facilities) with a capacity up to and including 500 kW_{el} • In addition, increase of 1 ct/kWh in the NawaRo bonus for electricity from biogas (new and existing facilities) with a capacity up to and including 150 kW_{el}, if at least at least 30% farm manure is used • Increase in the NawaRo bonus for electricity generated by the burning of wood from landscape management or short-rotation plantations, from 2.5 ct/kWh to 4 ct/kWh for facilities with a capacity of 0.5-5 MW_{el} • Increase in the CHP bonus from 2 to 3 ct/kWh. • Reduction in the degressive rate of remuneration for new facilities from 1.5% to 1% p. a.; introduction of annual degression of 1% for all (previously non-degressive) biomass bonuses from 2010 • Exclusion of palm and soya oil from the NawaRo bonus scheme until an effective certification scheme to safeguard their sustainable cultivation is in place • The principle of exclusive use to be elaborated and made more flexible; use of certain plant by-products in systems using cultivated biomass; pro rata remuneration based on a positive list	• Regular review and if necessary amendment of regulations concerning good practice in agriculture and forestry • Adoption of measures to reduce methane emissions from biogas facilities • The Federal Government to lobby at European level for the establishment of sustainability criteria for cultivated biomass. At the same time, the basis for authorisation to be introduced in the EEG for an ordinance which defines sustainability criteria for the cultivation of renewables. • Promotion of biogas microgrids via the Market Incentive Programme for Renewable Energies (MAP) / Joint Task of Improving Agricultural Structures and Coastal Protection (GAK) (or through inclusion in the technology bonus scheme).
Geothermal	• Reduction in the number of capacity categories from four to two, and increase in basic fees • Introduction of a heat cogeneration bonus of 2 ct/kWh • Introduction of a technology bonus of 2 ct/kWh for non-hydrothermal technologies	• Provision of support for development of local district and district heating networks, to distribute the waste heat utilised, through other funding programmes • Creation of a fund to provide security for the exploration risk, with drilling risks being covered by investment subsidies through the MAP • Further R&D measures
Wind energy	• Setting the rate of degression for new onshore wind farms at 1 to 2% p. a. • Improvement of repowering incentive in Article 10 (2) • Increase in grid stability by improving the technical properties of onshore wind farms; appropriate remuneration to be considered • Improvement in fees paid to offshore wind farms under Article 10 (3) by increasing initial fees from 8.74 to 11-15 ct/kWh, with a decrease in the lower rate of remuneration from 5.95 ct/kWh to 3.5 ct/kWh	• Development of a strategy for the utilisation of building planning law in order to boost repowering • Implementation of the strategy in dialogue with the federal states (*Länder*) with the aim of dismantling administrative obstacles at *Land* level • Assessment of how the interest of local communities in the establishment or renewal of wind farms (repowering) can be increased

Solar radiation	• Stepped increase in degressive rates to a standard 7% from 2009 and to 8% from 2011 • One-off reduction of 1ct/kWh in basic rate of remuneration from 1.1.2009 • Introduction of a new category for roof systems with a capacity of over 1000 kW_p and a reduction in the remuneration rate to 34.48 ct/kWh	
Future prospects	• More ambitious targets to be set in the Renewable Energy Sources Act for the share of renewable energies in electricity generation - 25-30% by 2020, to replace the current target of "at least 20%", and - continued steady expansion after 2020	

2 Mandate and Background

2.1 Legal mandate for the submission of the Progress Report 2007 on the Renewable Energy Sources Act

In view of the dynamic expansion of renewable energies (RE), regular monitoring of the existing support instruments and their individual impacts is required, which if necessary will allow an appropriate response and adjustment of the current legal provisions to de facto developments. In this way, positive trends can be reinforced and possible errors corrected. The purpose of this Progress Report is to facilitate this process.

Pursuant to Article 20 of the Renewable Energy Sources Act (EEG) of 21 July 2004 (Federal Law Gazette (*Bundesgesetzblatt*) 2004 I No. 40, p. 1918 ff), the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) shall, in agreement with the Federal Ministry of Food, Agriculture and Consumer Protection (BMELV) and the Federal Ministry of Economics and Technology (BMWi), submit a progress report to the German Bundestag on the Renewable Energy Sources Act by 31 December 2007.

The legal mandate for the submission of the Progress Report 2007 pursuant to Article 20 (1) of the Renewable Energy Sources Act [6] is as follows [direct quotation from the Act]:

> *"The Federal Ministry for the Environment, Nature Conservation and Nuclear Safety shall, in agreement with the Federal Ministry of Food, Agriculture and Consumer Protection and the Federal Ministry of Economics and Technology, report to the Bundestag by 31 December 2007 and subsequently every four years thereafter about the state of affairs with regard to the introduction to the market of plants generating electricity from renewable energy sources and from mine gas and about the development of electricity production costs in such plants and shall if necessary propose an adjustment of the amount of the fees to be paid in accordance with Articles 6 to 12 and of the degressive rates, in line with the development of technology and markets for plants commissioned after that date. The progress report shall also assess the storage technologies and the ecological effects of the use of renewable energy sources on nature and landscapes. The content of the report shall also include the activities of the Federal Network Agency pursuant to Article 19a."*

Article 16 (9) of the Renewable Energy Sources Act (Special equalisation scheme) [6] also makes reference to the Progress Report:

> *"Application of paragraphs (1) to (8) above shall be the subject of the progress report in accordance with Article 20."*

In compliance with the provisions of the Renewable Energy Sources Act (EEG), the Coalition Agreement [7] adopted by the CDU, CSU and SPD in autumn 2005 states as follows:

> *"We will therefore … maintain the basic structure of the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz - EEG) but at the same time review the economic efficiency of individual fees by 2007. In this context we will adjust fees, degression steps and funding periods to the development stages of individual renewable energies and, if necessary, define new priorities" and "concentrate on the repowering of existing wind power installations and on offshore wind energy generation and improve the framework conditions for these activities (e.g. expansion of the power grids)."*

The development of renewable energies is particularly dynamic in the electricity sector. Against this background, the present Progress Report describes the political parameters for, and the progress achieved with, renewables expansion in Germany and the various impacts of the Act itself. As well as addressing cross-sectoral aspects of renewables expansion in the electricity sector, it describes developments in the individual renewable energy sectors (hydropower, landfill and sewage gas, biomass, geothermal energy, wind power and solar radiation) as well as mine gas pursuant to Articles 6 to 11 EEG. It also looks at storage technologies and system integration, the special equalisation scheme under Article 16 EEG, and the future prospects for electricity generation from renewable energies. The report then formulates specific policy recommendations for each sector on that basis, taking particular account of trends over recent years and likely/desirable developments in the coming years. The purpose of these policy recommendations is to further optimise the effectiveness of renewables promotion in the electricity sector.

The policy recommendations contained in this report relate, firstly, to the Renewable Energy Sources Act itself and, secondly, to flanking measures of relevance to future renewables expansion in the electricity sector, whose implementation is likely to have a positive impact. These recommendations on measures outside the scope of the Act itself should be implemented independently of any amendment of the EEG so as not to unduly complicate the revision of the EEG and the Environmental Code.

2.2 Legislation and decisions on renewable energies, climate protection and energy policy

The new EEG, which entered into force on 1 August 2004, replaced the old Act which came into force on 1 April 2000. This in turn replaced the Electricity Feed Act (*Stromeinspeisungsgesetz* – StrEG), which came into force on 1 January 1991. This means that a legal basis for the expansion of renewable energies in the electricity sector has existed in Germany for 16 years. This expansion is of key importance for the Federal Government's climate and energy policy.

At its closed meeting in Meseberg, the Federal Cabinet agreed the key elements of an Integrated Energy and Climate Programme which includes the revision of the EEG.

In spring 2007, the European Council, under the German Presidency, set the course for an integrated European climate and energy policy, approving ambitious targets for climate protection and the expansion of renewable energies. For renewable energies, it set a binding target for the EU as a whole: a 20% share of renewable energies in overall EU energy consumption by 2020, i.e. approximately a threefold increase compared with 2005. It is important to note in this context that the 20% renewables share of total energy consumption does not have to be fulfilled by every individual Member State. Instead, the EU Member States will be required to meet different individual targets depending on their national framework conditions. These framework conditions depend, among other things, on the current share of renewables in electricity supply and on the country-specific potential for renewables expansion to 2020.

2.3 How does the EEG work?

The Renewable Energy Sources Act (EEG) of 21.7.2004

Germany's Act on Granting Priority to Renewable Energy Sources (Renewable Energy Sources Act – EEG) is an effective and efficient instrument to promote the expansion of renewable energies during the transition towards a sustainable energy system. It also supports the implementation of Directive 2001/77/EC of the European Parliament and the Council of September 2001 on the promotion of the electricity produced from renewable energy sources in the internal electricity market (COM 2001/77/EC) [8].

The specific aim of the EEG is to contribute to the increase in the percentage of renewable energy sources in power supply to at least 12.5% by 2010 and to at least 20% by 2020 (see Sections 3.1, 3.2 and 14), and thus to facilitate the sustainable development of the energy supply. It also aims to reduce the costs of energy supply to the national economy, also by incorporating long-term external effects, to contribute to avoiding conflicts over fossil fuels, and to promote the further development of technologies for the generation of electricity from renewable energy sources. Not least, the Act aims to protect nature and the environment. For that reason, in 2004, ecological criteria were incorporated into the Act's provisions on remuneration, along with a clause requiring the ecological effects of the use of renewable energy sources on nature and landscapes to be assessed in the Progress Report.

The core elements of the EEG are:

- the priority connection of installations for the generation of electricity from renewable energies and from mine gas to the general electricity supply grids,
- the priority purchase and transmission of this renewable-generated electricity,
- a consistent fee for this electricity paid by the grid operators, generally for a 20-year period, geared around the costs,
- the nationwide equalisation of the amounts of electricity purchased and the corresponding fees paid,
- the differential costs for renewable-generated electricity to be passed on to the final consumer.

The EEG provisions in detail

Obligation to purchase and transmit

Grid system operators are obliged to give immediate priority to connecting installations for the generation of electricity from renewable energies or from mine gas to their grid and to purchasing and transmitting all the electricity available from these installations. Plant operators bear the costs of connection to the grid. Grid system operators bear the necessary costs of upgrading the grid. They can take these costs into consideration when determining their charges for use of the grid.

The EEG creates incentives for operators of RE plants to agree on generation management with the grid system operators in their mutual interest. This is especially relevant for grid upgrading and control energy. This type of agreement can take account of the occasional fluctuations in the electricity supply, thereby minimising the costs for grid upgrades and reserve energy (see Chapter 5.2)

To facilitate better integration of renewable energies into the electricity system, installations with a capacity of 500 kilowatts or more are obliged to measure and record their capacity.

Fees

The EEG prescribes fixed tariffs which grid system operators must pay for the feed-in of electricity from hydropower, landfill gas, sewage and mine gas, biomass, geothermal and wind energy and solar radiation. The rate of fees depends on the electricity production costs in each case. Plants with higher electricity production costs receive higher payments, whereby technically optimised operation is assumed as a given. The electricity production costs depend, among other things, on the energy source, the technology and the point in time at which the installation of the system occurred. The minimum fees for each energy source are based on a sliding scale and vary depending on the size of the installation, and, in the case of wind energy, on the local wind conditions on site and whether it is generated on- or offshore. For 2008, fees range from 3.66 cents/kWh (for electricity from biomass plants which use waste wood classified in categories A III and A IV set out in the Waste Wood Ordinance) and 51.75 cents/kWh for solar electricity from small façade systems (for detailed figures, see Chapters 6 to 11). The average rate of remuneration for 2006 was 10.4 cents/kWh.

In general, the guaranteed payment period is 20 calendar years, and for hydropower 15 or 30 years, plus the year in which the plant was commissioned. The fee valid for the year in which the plant was commissioned remains constant throughout the remuneration period. The only exception to this rule is wind energy. Here, special regulations apply which deviate from the fixed fees for other energy sources.

In the case of wind energy, the "reference yield model" (*Referenzertragsmodell*) applies: its aim is to enable wind energy plants to operate throughout federal territory and therefore allows wind-generated electricity to be remunerated at different rates, depending on location. Therefore at prime coastal sites, higher starting fees are paid for the first five years after commissioning, whereas at inland sites, these higher starting fees are paid for longer. Wind farms at sites which can only achieve 60% of the reference yield receive the higher starting fees for up to 20 years. Fees are no longer paid to sites achieving less than 60% of the reference yield. The average period of higher starting fees paid under the reference yield system is estimated at approximately 16 years. There is a special incentive for repowering, i.e. the replacement of old and small plants by efficient modern systems, which is proving particularly effective at coastal locations.

For offshore wind farms, starting fees are paid for 12 years. This period is extended for installations located further from the coastline and erected in deeper water. The higher starting fees for offshore wind farms are paid for installations commissioned before 2010.

Tapering rates

In order to take account of technological developments in each renewables sector and to optimise the use of cost reduction potential, the remuneration rates are degressive in structure. Degression (tapering) means that there is an annual percentage reduction in the fees paid for new installations in all sectors (with the exception of small hydropower plants). The degressive rates range from 1% p.a. (e.g. for geothermal energy) to 6.5% p.a. (freestanding photovoltaic systems). For installed plants, the fee paid depends on the defined tariff in the year of commissioning. For geothermal and offshore wind installations, tapering only takes effect after a number of years.

Additional bonuses

For the bioenergy sector, in addition to the minimum fees laid down, the new version of the EEG provides for additional fees (bonuses) if the electricity is exclusively produced from the use of cultivated biomass or from heat and power cogeneration, or if the biomass was converted using innovative technologies (e.g. thermochemical gasification, fuel cells, gas turbines, organic Rankine systems, Kalina cycle plants or Stirling engines). The bonuses are intended to offer special incentives for the use of existing biomass potential, efficient heat and power cogeneration and innovative technologies and can be applied cumulatively.

Equalisation mechanism

Due to the different rate of expansion of renewable energies in the various regions of Germany, electricity consumers would be exposed to different financial burdens resulting from the additional costs arising from the generation of electricity under the EEG (for example, due to wind conditions, considerably more electricity is generated from wind power in northern than in southern Germany). To prevent regional inequality in the treatment of electricity consumers, the transmission grid operators must undertake a nationwide equalisation of the electricity volumes purchased under the EEG and the corresponding fees.

Supplementary regulations

Aspects of nature conservation and landscape management are given particular consideration in the individual renewable sectors. To improve transparency, the EEG obliges grid system operators to publish energy volumes and payment figures. To provide better information on the current status and expansion of renewables use, the EEG allows for the establishment, through an ordinance, of a public register of installations.

Since July 2003, the EEG has contained provisions on a special equalisation scheme which has since been expanded on two occasions. It caps the costs of renewable-generated electricity for certain energy-intensive manufacturing enterprises and rail operators. The aim is to avoid a situation in which these enterprises' (international) competitiveness is put at risk as a result of the application of the EEG.

In accordance with the provisions laid down by the European Union, the EEG allows authorised bodies to issue guarantees of origin for electricity from renewable energies. This is intended to promote consumer information and protection.

The prohibition of multiple sale makes it clear that the positive environmental characteristics of electricity from renewable energies may not be sold multiple times, e.g. through payment for feed-in of renewable-generated electricity under the Act and, at the same time, the achievement of a higher market price for "green" electricity. The ban also extends to the relevant guarantees and the simultaneous sale and passing on of guarantees for the same electricity (see Chapter 5.5).

To clarify issues of application and to resolve disputes, a clearing house was established in the BMU on 15 October 2007.

3 Overview of the Development of Renewable Energies in Germany

All the statistical data contained in this Progress Report for 2004, 2005 and 2006 are provisional. Data research for 2006 is currently in progress and the results will be available in mid-December (on data availability, see Chapter 5.3).

The statistical data used and presented in this chapter are based on information which was current as of July 2007. However, more recent data, especially figures published by the Association of German Network Operators (VDN) on 21 September 2007, have been incorporated into the report as far as possible.

The data obtained from the VDN publication of 21 September 2007 diverge slightly from the data used as the basis for the preparation of the present report which were current as of July 2007. This applies especially to the figure for the production of electricity from renewable energies, which is lower by around 2.6 TWh. This is due primarily to the lower current values for the generation of electricity from biomass remunerated under the EEG and for traditional hydropower, most of which does not qualify for payments under the EEG. Overall, the current data show that renewable energies accounted for around 11.6% of gross electricity consumption in 2006, i.e. around 0.4 percentage points lower than assumed in July 2007. Nonetheless, the statements and conclusions drawn in this Progress Report continue to apply unchanged, notwithstanding the slightly amended statistical basis.

The same applies in some cases to the presentation and use of data from July 2007 in Chapters 4, 6, 7, 8, 9, 10, 11, 13, and 14.

3.1 Renewables contribution to primary energy and final energy supply

Renewables use continued to show very positive trends in 2006. The share of renewables in primary energy consumption rose from around 4.7% in 2005 to approximately 5.8% in 2006 (calculated on the basis of the physical energy content method). This is more than double the 2000 figure (2.6%). The share of renewables in total final energy consumption (electricity, heating, fuels) rose from 3.8% (2000) to 6.6% in 2005 and around 8.0% in 2006.

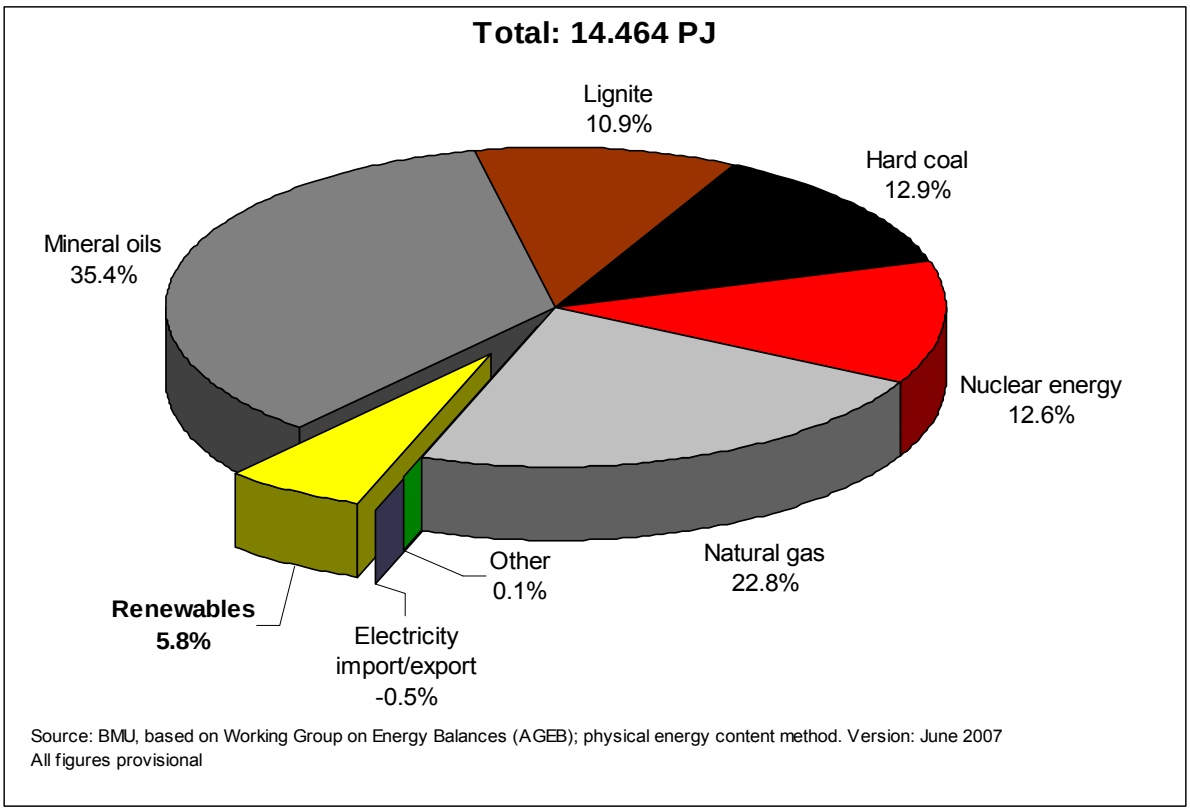


Fig. 3-1: Structure of primary energy consumption in Germany in 2006 [1]

The share of renewable-generated electricity in total gross electricity consumption amounted to 11.6% in 2006 (2005: 10.4%). Germany met its national target set at EU level – to increase the share of renewable energies in electricity generation to at least 12.5% by 2010 – in 2007, with a figure above 13% forecast for 2007

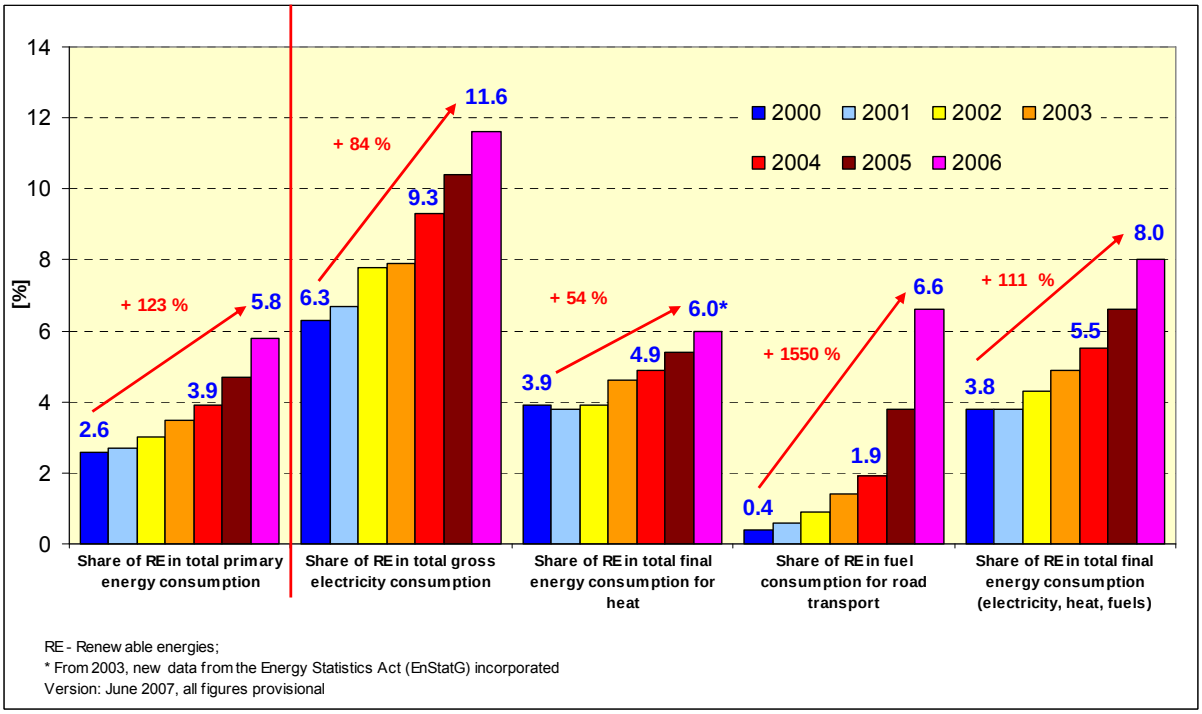


Fig. 3-2: Contribution of renewable energy sources to energy supply in Germany 2000-2006 [1]

Table 3-1: Share of renewable energy sources in Germany's energy supply, 1998-2006 [2]

	1998	1999	2000	2001	2002	2003	2004*)	2005*)	2006*)
Final energy consumption (FEC)	[%]								
Electricity generation (based on total gross electricity consumption)	4.8	5.5	6.3	6.7	7.8	7.9	9.3	10.4	approx. 11.6
Heat supply (based on total heat supply)	3.5	3.5	3.9	3.8	3.9	4.6	4.9	5.4	6.0
Fuel consumption (based on total road transport)	0.2	0.2	0.4	0.6	0.9	1.4	1.9	3.8	6.6
RES share of total final energy consumption in Germany	**3.1**	**3.3**	**3.8**	**3.8**	**4.3**	**4.9**	**5.5**	**6.6**	**approx. 8.0**
Primary energy consumption (PEC)	[%]								
Electricity generation (based on total PEC)	0.8	0.9	1.1	1.1	1.4	1.5	1.6	2.1	2.5
Heat supply (based on total PEC)	1.3	1.3	1.4	1.4	1.5	1.8	1.9	2.0	2.2
Fuel consumption (based on total PEC)	0.03	0.03	0.06	0.1	0.1	0.2	0.3	0.6	1.0
Share of PEC	**2.1**	**2.2**	**2.6**	**2.7**	**3.0**	**3.5**	**3.9**	**4.7**	**5.8**

PEC calculated according to physical energy content method

*) Figures provisional, in some cases estimated

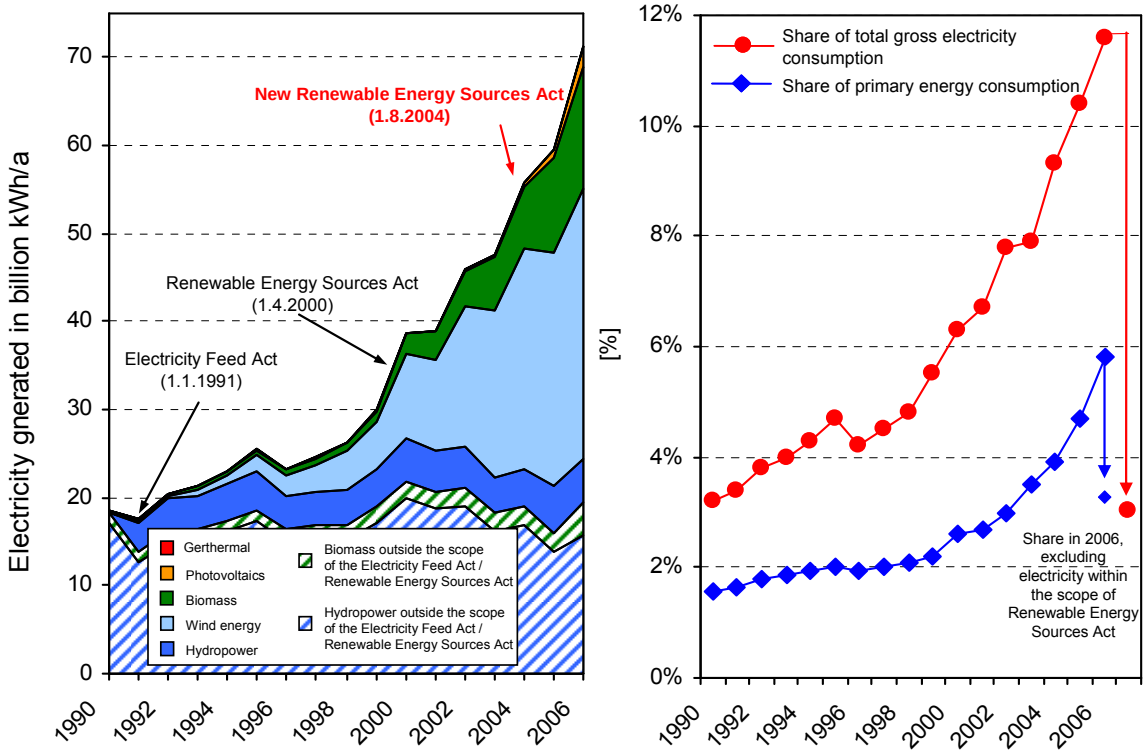


Fig. 3-3: Development of electricity production from renewable energies and their contribution to gross electricity consumption and primary energy consumption for the period 1990-2006 (calculated using the physical energy content method) [1]

3.2 Contributions of individual RE sectors

Table 3-2: Contribution of renewable energy sources to energy supply in Germany in 2006 [4]

Final energy supply	[TWh]
Wind energy	**30.7**
Hydropower	**20.7**
Biomass	**15.6**
of which solid biomass, including biogenic waste	10.2
of which biogas	4.2
of which liquid biomass	1.3
Landfill and sewage gas	**2.0**
Photovoltaics	**2.2**
Geothermal energy	**0.0004**
Total electricity	**71.2**

Wind energy

In 2006, wind energy accounted for the largest share of electricity production from renewable energies, with around 30.7 billion kWh, i.e. around 5% of Germany's total gross electricity consumption (2005: 27.2 billion kWh). At the end of 2006, a total of 18,685 wind energy plants were in operation in Germany, with an installed capacity of 20,622 MW.

Table 3-3: Development of wind energy use, 2000-2006 [2, 4]

Wind energy	2000	2001	2002	2003	2004	2005	2006
Electricity generated [TWh]	7.6	10.5	15.8	18.9	25.5	27.2	30.7
Installed capacity [MW]	6,112	8,754	11,965	14,609	16,629	18,428	20,622
Increase in capacity [MW/a]	1,668	2,642	3,211	2,644	2,020	1,799	2,194

Hydropower

Electricity generation from hydropower has generally remained stable at around 20.7 billion kWh in recent years. There has been little increase in installed capacity in this sector, and the weather conditions in 2006 also did not lead to any significant change in electricity output.

The fluctuations in electricity generation from hydropower are mainly caused by varying amounts of precipitation.

Table 3-4: Development of hydropower use, 2000-2006 [2, 4]

Hydropower	2000	2001	2002	2003	2004	2005	2006
Electricity generated [TWh]	24.9	23.4	23.8	20.4	21.0	21.5	20.7
Installed capacity [MW]	4,572	4,600	4,620	4,640	4,660	4,680	4,700
Increase in capacity [MW/a]	25	28	20	20	20	20	20

Biomass

Electricity generation from total biomass amounted to around 17.6 billion kWh in 2006 (2004: around 10.5 billion kWh), i.e. around 2.9% of Germany's total gross electricity consumption. Electricity generation from biogas showed a strong upward trend, rising from around 2.8 billion kWh in 2005 to around 4.2 billion kWh in 2006.

Table 3-5: Development of biomass use, 2000-2006 [2, 4]

Biomass	2000	2001	2002	2003	2004	2005	2006
Electricity generated [TWh]*	4.1	5.1	6.0	9.1	10.5	13.5	17.6
Installed capacity [MW]*	664	790	952	1,137	1,550	2,192	2,740
Increase in capacity [MW/a]*	60	126	162	185	413	642	598

* Solid, liquid, gaseous biomass, landfill and sewage treatment plant gas; share of biogenic waste in waste incineration plants estimated at 50%

Solar radiation

A clear increase can be noted for electricity generation from solar radiation (photovoltaics) as well. This rose from around 0.6 billion kWh in 2004 to approx. 2.2 billion kWh in 2006.

Table 3-6: Development of photovoltaics use, 2000 – 2006 [2, 4]

Photovoltaics	2000	2001	2002	2003	2004	2005	2006
Electricity generated [TWh]	0.06	0.12	0.19	0.31	0.56	1.28	2.22
Installed capacity [MW_P]	100	178	258	408	1,018	1,881	2,831
Increase in capacity [MW/a]	42	78	80	150	610	863	950

Geothermal energy

There is still only one plant generating electricity from geothermal energy in operation in Germany, namely in Neustadt-Glewe (Mecklenburg-Western Pomerania), which came onstream in 2003. However, a number of other projects have reached various stages in the development process. Two geothermal power plants – in Unterhaching near Munich and in Landau – are scheduled to come onstream before the end of 2007. All the plants use aquifers.

Table 3-7: Development of geothermal use, 2000-2006 [2, 4]

Geothermal energy	2000	2001	2002	2003	2004	2005	2006
Electricity generated [TWh]	0.0	0.0	0.0	0.0	0.0002	0.0002	0.0004
Installed capacity [MW]	0.0	0.0	0.0	0.0	0.2	0.2	0.2
Increase in capacity [MW/a]	0.0	0.0	0.0	0.0	0.2	0.0	0.0

Table 3-8 shows how the contributions of the various renewable energy sources to electricity generation in Germany have developed since 1990.

Table 3-8: Contribution of renewable energy sources to electricity generation in Germany, 1990-2006 [2, 4]

	Hydro-power	Wind energy	Biomass **	Photo-voltaics	Geo-thermal	Total electricity generation from renewables	Share of gross electricity consumption
				[GWh]			
1990	17,000	40	1,422	1	0	**18,463**	**3.4**
1991	15,900	140	1,450	2	0	**17,492**	**3.2**
1992	18,600	230	1,545	3	0	**20,378**	**3.8**
1993	19,000	670	1,570	6	0	**21,246**	**4.0**
1994	20,200	940	1,870	8	0	**23,018**	**4.3**
1995	21,600	1,800	2,020	11	0	**25,431**	**4.7**
1996	18,800	2,200	2,203	16	0	**23,219**	**4.2**
1997	19,000	3,000	2,479	26	0	**24,505**	**4.5**
1998	19,000	4,489	3,392	32	0	**26,913**	**4.8**
1999	21,300	5,528	3,641	42	0	**30,511**	**5.5**
2000	24,936	7,550	4,129	64	0	**36,679**	**6.3**
2001	23,383	10,509	5,065	116	0	**39,073**	**6.7**
2002	23,824	15,786	5,962	188	0	**45,760**	**7.8**
2003	20,350	18,859	9,132	313	0	**48,654**	**7.9**
2004*	21,000	25,509	10,463	557	0.2	**57,529**	**9.3**
2005*	21,524	27,229	13,534	1,282	0.2	**63,569**	**10.4**
2006*	20,673	30,710	17,626	2,220	0.4	**71,230**	**11.6**

* Figures provisional, in some cases estimated; some based on VDN calculations

** Solid, liquid, gaseous biomass, biogenic share of waste, landfill and sewage gas

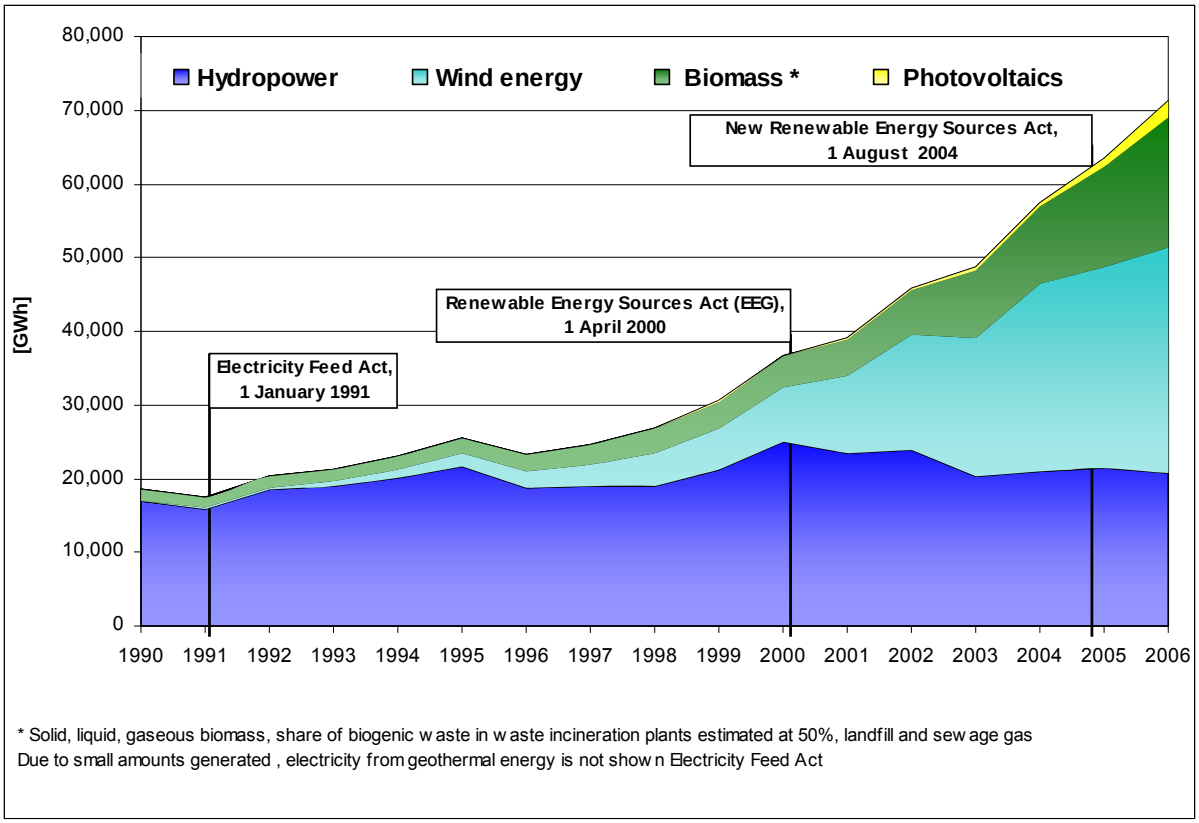


Fig. 3-4: Contribution of renewable energies to electricity generation, 1990-2006 [2, 4]

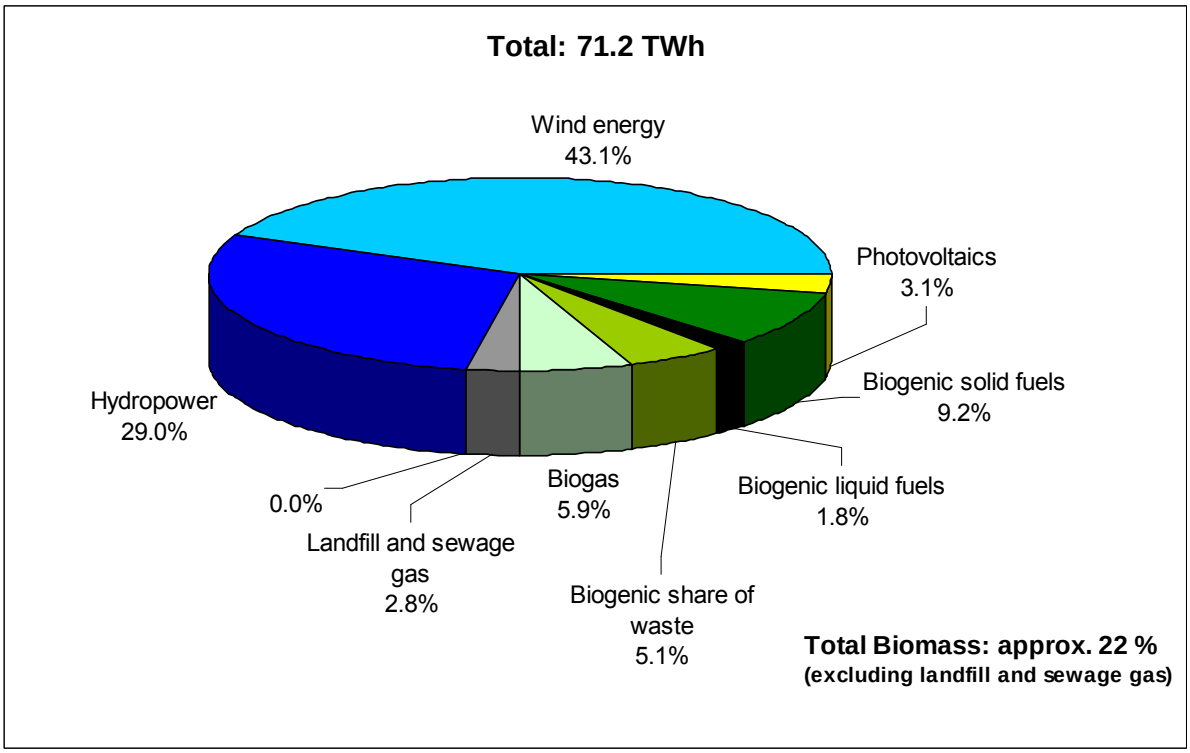


Fig. 3-5: Structure of electricity generation from renewable energy sources in Germany in 2006 [2]

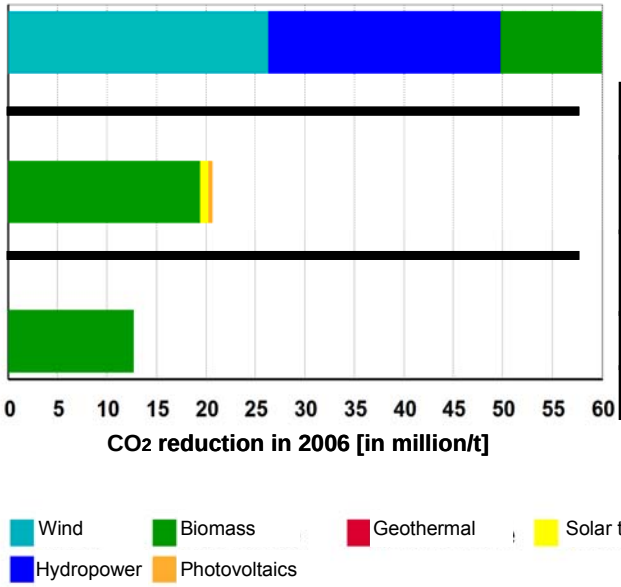
4 Impacts of the Renewable Energy Sources Act (EEG)

Until 1990, the development of renewable energies in Germany was dominated by the traditional use of wood for heating and hydropower for electricity generation. The use of other renewable energy sources, also in conjunction with modern technologies, was still at the research and development (R&D) stage. These R&D efforts from as early as 1970, as well as relevant policy measures, have since then made it possible to harness the "new" renewable energies – wind, solar and geothermal energy – as well, and to develop and implement modern processes for the use of biomass for energy.

The **Renewable Energy Sources Act (EEG)**, which was introduced in 2000, plays a key role in this context. It replaced and greatly improved upon the **Electricity Feed Act** (*Stromeinspeisungsgesetz* – StrEG), which had been in force since 1991. The current Renewable Energy Sources Act (EEG) came into force on 1 August 2004. Its provisions – especially the obligation of grid operators to connect RE systems to the grid and purchase and transmit RE-generated electricity at fixed tariffs per kilowatt hour – have established appropriate and calculable parameters for investment and borrowing for RE plants and related production facilities. The ensuing investment security has triggered a renewables boom in the electricity sector and the RE production industry, to worldwide acclaim. What's more, the high level of investment security also has the potential to push down the price of borrowing and reduce investors' demands for high returns on their investment, directly cutting the costs of renewables expansion. Investment security also speeds up technological development, which can help to reduce costs as well.

4.1 The contribution of renewable energies and the EEG to climate protection

In 2006, carbon dioxide (CO_2) emissions were reduced by around 44 million tonnes through the promotion of renewables in the electricity sector (2005: 38 million tonnes of CO_2). [1]. No other instrument (e.g. the Act on Combined Heat and Power Generation, emissions trading, the ecological tax reform, the Market Incentive Programme for Renewable Energies, etc.) has resulted in similar CO_2 reductions. In total, carbon dioxide (CO_2) emissions were reduced by around 100 million tonnes in 2006 through the use of renewable energies in the electricity, heat and fuel sectors in Germany [**1**].



Electricity generation	Largely substituted		

Fig. 4-1: Total CO_2 avoidance through the use of renewable energy sources, 2006, based on [1]

Almost half the total reduction in carbon dioxide (CO_2) emissions achieved through renewables use in 2006 (i.e. around 44 million tonnes) was due to the effects of the EEG (Fig. 4-1). The same applies to the reduction in the emission of air pollutants such as sulphur oxides, nitrogen oxides etc. and savings on fossil fuels [**1**].[1]

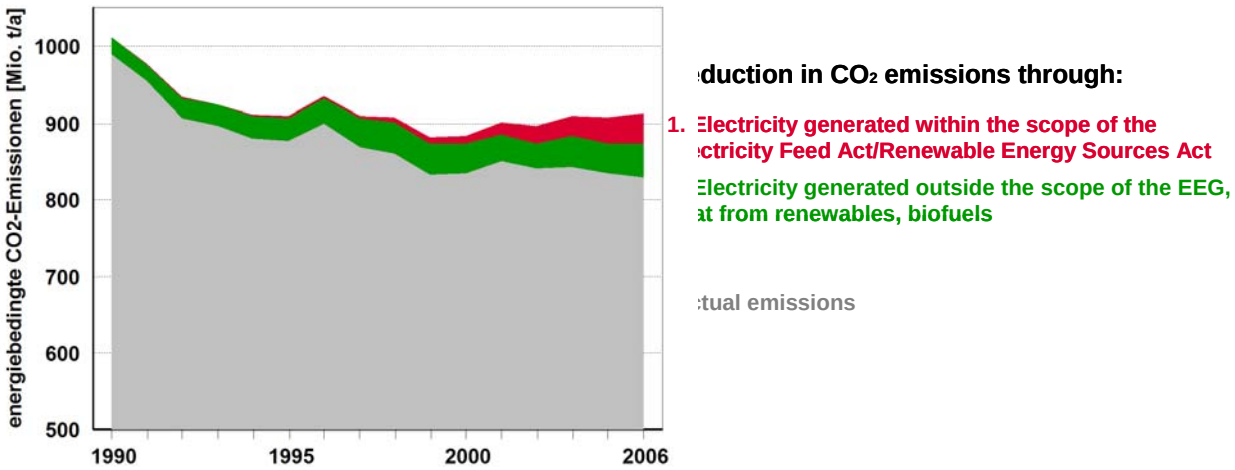


Fig. 4-2: Development of energy-related CO_2 emissions in Germany, 1990-2006 [2]

[1] For details, see [2]

The costs of CO_2 avoidance through renewables use have been analysed in a number of studies. Table 4.1 provides an overview of the findings of three studies from the last three years. Due to their divergent assumptions and methodologies, their findings span a broad spectrum. Nonetheless, the DLR Lead Study (2004) and the dena Grid Study I (2005) both predict that CO_2 avoidance costs will fall (except in the hydropower sector) due to cost degression (learning curve) effects in renewable energy technologies and the anticipated rising costs of fossil fuels. However, their conclusions differ as regards the rate at which this is likely to occur.

More recent findings on the costs of generating electricity from biogas, offshore wind energy and photovoltaics, obtained since the publication of the above studies, have implications for the calculation of CO_2 avoidance costs, but are not shown here. Compared with the studies mentioned above, which were published in 2004 and 2005, this new research suggests that CO_2 reduction costs will probably increase in the case of biogas and offshore wind, but will are likely to fall in the case of photovoltaics.

Table 4-1: CO_2 avoidance costs of renewable energy technologies (€/t CO_2) [9, 10, 11]

		Lead Study (2004) [1)]			dena Grid Study I (2005) (alternative scenario)[2)]			Munich TU
		2000	2010	2020	2007	2010	2015	2020
Wind energy								70
	Onshore	45	35	20	168	57	41	
	Offshore	-	52	32				
Hydropower								22
	Above 1 MW	18	25	30				
	Less than 1 MW	28	40	61				
Biomass CHP		50	38	21				
Photovoltaics		970	720	450				1.944

1) Costs in € (2004); price development of mid-range fossil fuels; relates to a mix of new fossil condensing power stations in line with the reference scenario.

2) Costs in € (2003); price development of "high gas prices" and CO_2 certificate prices rising from 5 €/t CO_2 in 2005 to a constant 12.5 €/t CO_2 from 2013 (real prices).

4.2 The impact of the EEG on nature and landscape

In principle, renewables expansion is in the interests of nature conservation, but can only be sustainable if implemented in a way which leaves no more than a small footprint in the natural environment. The EEG makes a contribution to this process.

Since 2004, the EEG has contained core provisions which are intended to take account of potential conflicts relating to the ecological effects of the use of renewable energy sources on nature and landscapes, preserve biological diversity and allow appropriate changes to be made if this should prove necessary. The aim is to ensure that renewables expansion is in harmony with the interests of the natural environment. Pursuant to Article 20 (1) EEG, the ecological effects of the use of renewable energy sources on nature and landscapes must be assessed in this progress report. The chapters dealing with the individual renewables sectors therefore contain summarised evaluations and relevant recommendations.

A fundamental and specific need for research has been identified across all sectors. This issue is already being addressed by the federal ministries and their subordinate bodies.

4.3 Development of fees, differential and macroeconomic costs of the EEG

The Renewable Energy Sources Act (EEG) has proved to be a key instrument in the expansion of renewable energies in the electricity sector. However, renewable energies are still not price-competitive with conventional electricity generation and could not survive in the market without the financial support provided under the Renewable Energy Sources Act. This applies to the individual RE sectors to varying extents. Onshore wind power is closest to being competitive, whereas photovoltaics still has a long way to go (see also Fig. 14-3 and Fig. 14-4).

Table 4-2: Feed-in tariffs for RE plants commissioned in 2007 (see also the separate chapters on the individual RE sectors 6.1 to 11.1)

	Feed-in tariffs (2007) [cents/kWh]
Hydropower	3.58 – 9.67
Landfill, sewage and mine gas	6.35 – 7.33
Biomass	8.03 – 20.99
Geothermal energy	7.16 – 15.00
Wind energy	5.17 – 9.10
Solar radiation	37.96 – 54.21

The average payment under the EEG has risen from 8.5 cents/kWh in 2000 to 10.9 cents/kWh in 2006 (see Table 4-3).

As long as renewable energies remain uncompetitive, plant operators will continue to be reliant on the fees paid under the Renewable Energy Sources Act. Due to the rapid expansion of renewable energies in the electricity sector, the total fees paid under the EEG rose substantially from around €1.3 billion in 2000 to approx. €5.8 billion in 2006. This is a far higher figure than was anticipated at the time of the EEG's revision in 2004, when a total figure of €3.8 billion was forecast for 2010, and is mainly due to the greater-than-predicted increase in the amount of electricity being generated under the EEG.

Table 4-3: Development of average EEG payments per sector in cent/kWh, 2000-2006, based on [4]

	Hydro-power [ct/kWh]	Landfill, sewage and mine gas [ct/kWh]	Biomass [ct/kWh]	Geo-thermal [ct/kWh]	Wind energy [ct/kWh]	Solar radiation [ct/kWh]	Average EEG payment [ct/kWh]
2000	7.21		9.62		9.10	51.05	8.50
2001	7.25		9.51		9.10	50.79	8.69
2002	7.25		9.49		9.09	50.43	8.91
2003	7.24		9.38		9.06	49.11	9.16
2004	7.32	7.04	9.70	15.00	9.02	50.83	9.29
2005	7.35	6.99	10.80	15.00	8.96	52.96	10.00
2006	7.45	7.01	12.27	12.50	8.90	53.01	10.88

Table 4-4: Development of total EEG payments, 2000-2006 in € million [4]

	Hydro-power [€ million]	Landfill, sewage and mine gas [€ million]	Biomass [€ million]	Geo-thermal [€ million]	Wind energy [€ million]	Solar radiation [€ million]	Total [€ million]
2000	396[1)]		75		687	19	1,177
2001	442[1)]		140		956	39	1,577
2002	477[1)]		232		1,435	82	2,226
2003	428[1)]		327		1,696	154	2,604
2004	338	182	509	0.0	2,301	283	3,612
2005	364	219	795	0.0	2,441	679	4,498
2006	367	196	1,337	0.0	2,734	1,177	5,810

[1)] Including landfill, sewage and mine gas

When calculating the costs of the EEG, it is not only the fee payments which are of relevance, however; the differential costs, which are legally defined in Article 15 EEG, must also be taken into account. These are the additional costs resulting from the total fee payments for renewable-generated electricity as compared with energy supply companies' average avoided costs of purchasing the conventional electricity that would have been required without the feed-in of electricity from renewable sources under the Act, and which would have been charged to electricity consumers via their fuel bills. The energy supply companies generally pass on these differential costs to the consumer through a surcharge on the electricity price.

Table 4-5: Development of the EEG differential costs, 2000-2006, in € million (without deduction of avoided grid utilisation fees)

	Hydropower [€ million]	Landfill, sewage and mine gas [€ million]	Biomass [€ million]	Geothermal [€ million]	Wind energy [€ million]	Solar radiation [€ million]	Total[2] [€ million]
2000	282	0	59	0	530	19	889
2001	295	0	105	0	703	37	1,139
2002	329	0	177	0	1,080	78	1,664
2003	253	0	224	0	1,144	144	1,765
2004	200	105	352	0	1,540	266	2,464
2005	180	103	521	0	1,428	631	2,863
2006	149	73	857	0	1,379	1,079	3,537

The development of the differential costs arising from the EEG is shown in Tab. 4-5. In 2006, they amounted to around €3.3 billion (applicable value for electricity generated under the Act: 4.4 cents/kWh, according to IfnE and DIW [12]). Due to the substantial expansion of renewables, a significant increase on this figure is expected for 2007: VDN, which – as experience shows – generally forecasts higher values than subsequently occur in practice, predicts a figure of €4.7 billion for 2007, based on an approx. 14.5 per cent share of renewables in gross electricity consumption.

The EEG surcharge payable by the consumer varies according to the different electricity consumer groups. The absolute and, indeed, the relative charge is largely dependent on the level and intensity of electricity consumption. On average, the surcharge for electricity consumers with no preferential treatment under Article 16 of the Renewable Energy Sources Act amounted to around 0.7 cents/kWh in 2006: in other words, the EEG surcharge accounted for less than 4% of the average price of residential electricity [13]. 75.1% of the electricity price increases between 2002 and 2006 for private households was due to production, transport and distribution costs. The electricity tax levied as part of the ecological tax reform accounted for 9.0% of the electricity price increases, the EEG for 13.1%, and the CHP Act for 2.8%. There was also an increase in the rate of value added tax on 1 April 1996 and again on 1 January 2007.

The electricity price for residential consumers is around 19 cents/kWh – far higher than the electricity price for industrial consumers, who can generally agree their own prices with electricity suppliers and grid operators. The price negotiated by these major clients on an individual basis averages around 4.5 cents/kWh. Reflecting this broad electricity pricing band, the percentage of the price that derives from the EEG also varies, amounting to around 4% of the average residential electricity price (19 cents/kWh), but as much as 8.5% of the electricity price for manufacturing enterprises which are not eligible for relief under the special equalisation scheme [14].

For the purposes of illustration, Table 4-6 provides an overview of the average EEG surcharges for selected electricity consumer groups. It also shows the EEG surcharge as an

[2] Excluding avoided grid utilisation charges; if these are deducted, as is customary in VDN calculations, this gives a figure of € 3.3 billion for total EEG differential costs.

average percentage of electricity costs for these consumer groups, and as a share of turnover [14].

Table 4-6: Overview of the average impact of the EEG surcharge on selected electricity consumer groups, 2005 [14]

Electricity customer	EEG surcharge [€ / year]	Share of electricity costs [%]	Share of turnover [%]
3-person household	23	3.65	0.05
Retail	526	4.80	0.02
Hospital sector	13,138	7.38	0.09
Non-privileged consumers in manufacturing industry	59,202	8.45	0.59
Privileged consumers in manufacturing industry	10,839	1.63	0.11
Part-privileged consumers in manufacturing industry	101,954	2.01	0.17
Fully privileged consumers in manufacturing industry	528,000	1.03	0.12

Besides the differential costs associated with the Renewable Energy Sources Act, other cost impacts of renewables expansion can also be noted, which have an indirect effect on the electricity consumer but which cannot be fully quantified due to their complexity:

- Additional need for controlling and balancing energy due to fluctuating feed-in, especially in the case of wind-generated electricity.
- No optimal cost-effective, full-capacity utilisation of existing conventional power plants, due to the priority feed-in of RE electricity under the Act.
- Additional costs of grid expansion and conversion due to regionally concentrated electricity generation from windpower, often at some distance from final consumers.
- The shifting of grid expansion costs from plant operators to grid systems operators through the Infrastructure Planning Acceleration Act
- Transaction costs for the transmission grid operators incurred for accounting under the EEG.
- Grid operators' costs of complying with the transparency rules contained in Article 15 ff EEG.
- The Federal Network Agency's costs of monitoring the transparency rules.

As far as the law permits, these EEG-related additional costs are passed on via the grid utilisation charges levied by grid operators, thereby increasing the general electricity price, and are factored into production costs.

4.4 Positive macroeconomic impacts of the EEG, turnover and employment effects

The EEG has not only micro- but also macroeconomic effects, which cannot be offset against each other or against the EEG-related costs.

- A relevant effect of the EEG is the avoidance of external costs. Through the substitution of fossil fuels in electricity generation, the EEG substantially reduces CO_2-related damage in particular and hence its resulting external costs.
- The EEG reduces hard coal and gas imports for electricity generation in Germany, which saved around €0.9 billion in 2006 [**2**].

BMU takes the view that due to the electricity market's specific pricing mechanisms, the Renewable Energy Sources Act, by increasing the electricity supply, has also had a notable price-dampening effect on wholesale electricity prices in Germany in recent years (i.e. the merit order effect). However, the Federal Ministry of Economics and Technology considers that it is wrong to depict the merit order effect as a saving for the consumer, as no conclusions can be drawn about the general impact of renewables from short-term price effects on the spot market resulting from the priority feed-in, under the Act, of RE electricity for which there is no demand.

The Renewable Energy Sources Act generates considerable impetus for innovation and employment, which is reinforced through measures in the fields of research and development (R&D) and export promotion, etc. A new industry has thus become established in Germany which has succeeded in placing all renewable energy sectors in a leading technological position worldwide. This applies not only to systems manufacturers and suppliers, but especially to component manufacturers and distributors. This is already resulting in notable export successes. In 2006, for example, more than 70% of the wind power plants produced in Germany was exported.

Renewable energies have become an increasingly important economic factor in Germany (see also Chapter 14.3). According to an initial analysis prepared for the BMU, domestic turnover increased by €10.6 billion to around €22.9 billion in 2006 compared with the 2004 figure, i.e. an increase of 86% (see Fig. 4-3), with around two-thirds of this – some €15 billion – arising in the electricity sector, of which the major share (around €14.2 billion) was directly attributable to electricity generation under the Renewable Energy Sources Act (see Fig. 4-4).

Between 2002 and 2006, cumulative turnover in the electricity sector totalled around €53 billion, 60% of which consisted of investment in new plant and a good 40% in the operation of RE systems. Exports are likely to play an increasingly important role in future.

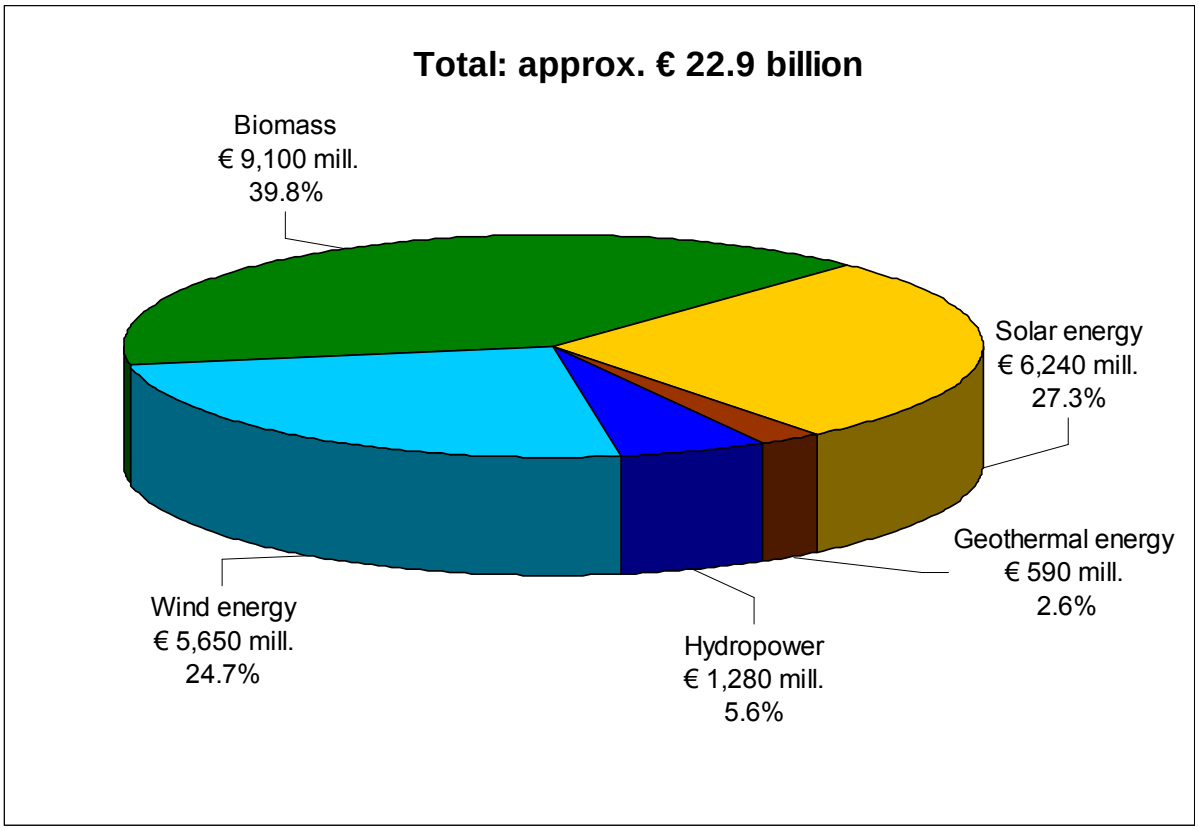


Fig. 4-3: Total turnover with renewable energy sources in Germany, 2006 (investments and operation) [2]

Linked to this, there has been significant growth in employment in the renewables industry. According to a research project by the Zentrum für Sonnenenergie- und Wasserstoff-Forschung Baden-Württemberg (Center for Solar Energy and Hydrogen Research Baden-Württemberg – ZSW) [3], completed in September 2007, the number of people working directly and indirectly in all the renewable energy sectors (electricity, heating and biofuels) in Germany has increased by around 50% from 160,000 in 2004 to around 236,000 in 2006. In other words, 75,000 new jobs were created, and the number of jobs in the renewables industry was two and a half times higher in 2006 than in 2000. This includes foreign trade, upstream value-added stages and jobs resulting from investment in renewable energies by the public and non-profit sectors, but does not include employment effects resulting from the expansion of production capacity (2006: around 23,500 jobs, of which around 12,900 are attributable to the Renewable Energy Sources Act).

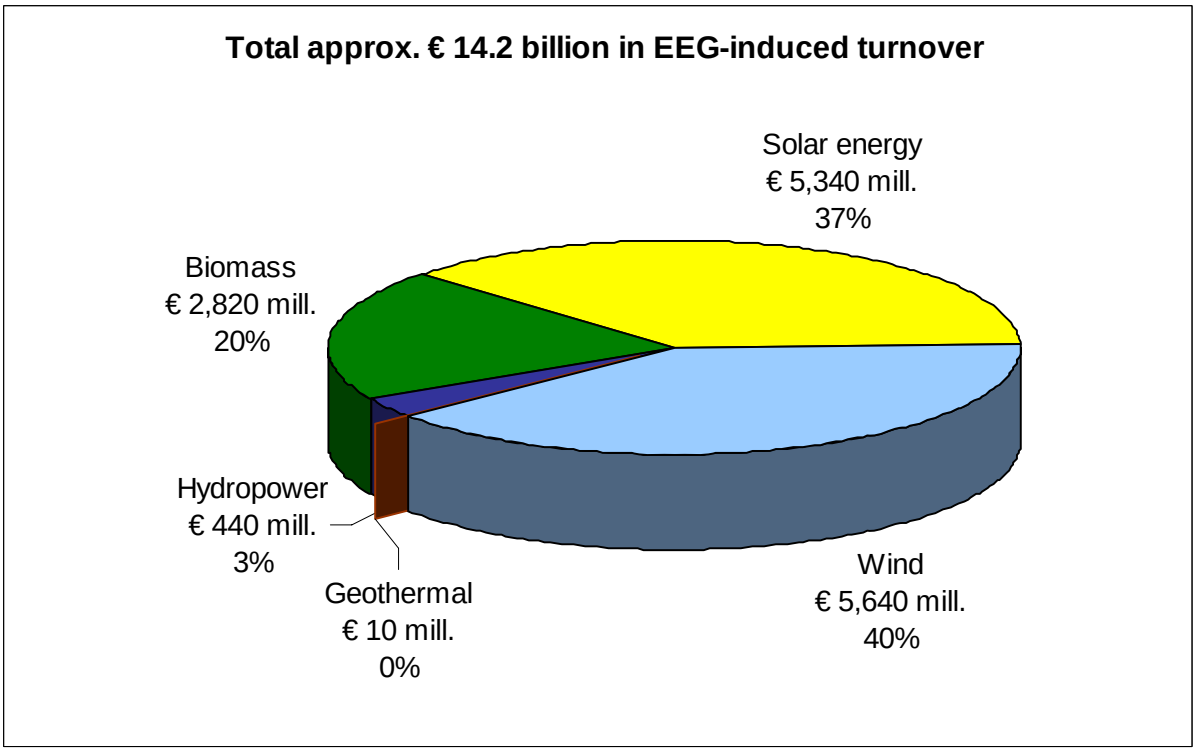


Fig. 4-4: **Total turnover with renewable energy sources in Germany attributable to the EEG, 2006 (investments and operation) based on [1, 3]**

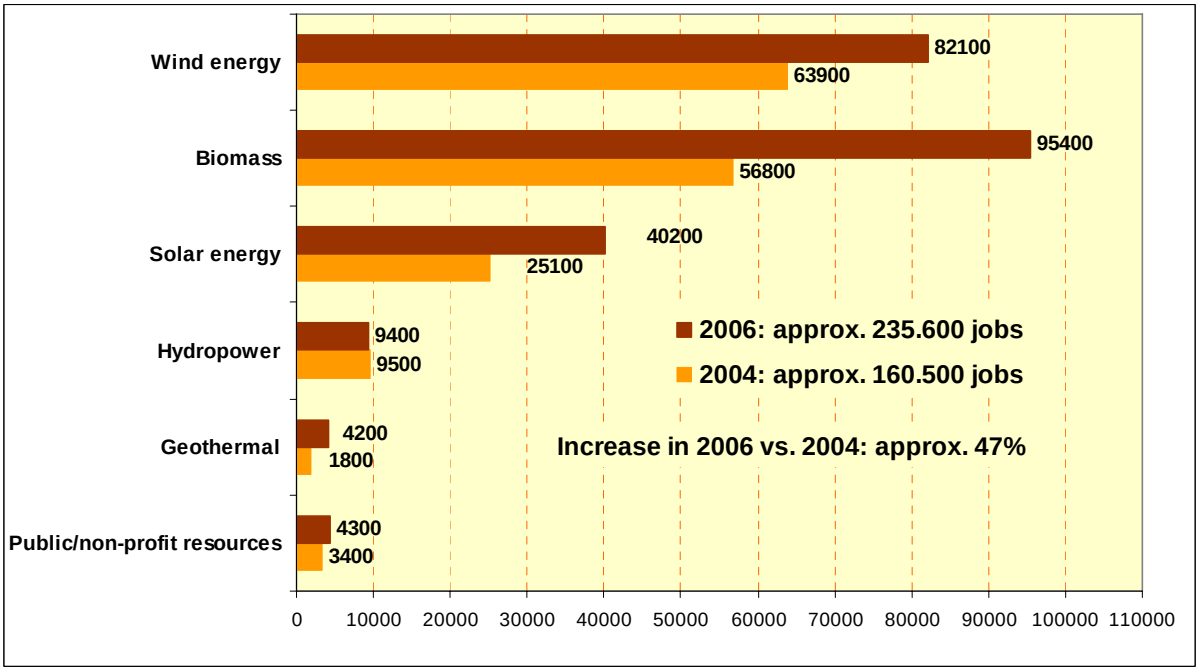


Fig. 4-5: **Jobs in the renewable energies sector (electricity, heating, fuels) in Germany in 2004 and 2006 [3]**

The main contributory factors to this increase in jobs include the high demand for heat generation plants due to the high oil and gas prices, increased production of systems and components, especially in the biogas and photovoltaics sectors, the export successes of Germany's wind power industry, and the significant increase in the supply of biogenic fuels and biofuels.

Of the figure of 236,000 jobs calculated for 2006, around 134,000 (i.e. 60%) result from the Renewable Energy Sources Act. For reasons of methodology, jobs resulting from the investment of public and non-profit resources are not included (as they cannot be clearly ascribed to the effects of the EEG). With 82,000 jobs in 2006, wind energy accounted for much more than half of the EEG-induced jobs (2004: 64,000 jobs). There was a substantial increase – more than 40% – in jobs in the photovoltaics sector, with 27,000 jobs in 2006 compared with around 17,500 in 2004. Power generation from biomass accounted for around 22,000 jobs (2004: 14,000), while hydropower's contribution remained fairly constant, with 3,000 jobs. During the period under review, electricity generation from geothermal energy had minimal employment effects, although this situation is likely to change in future.

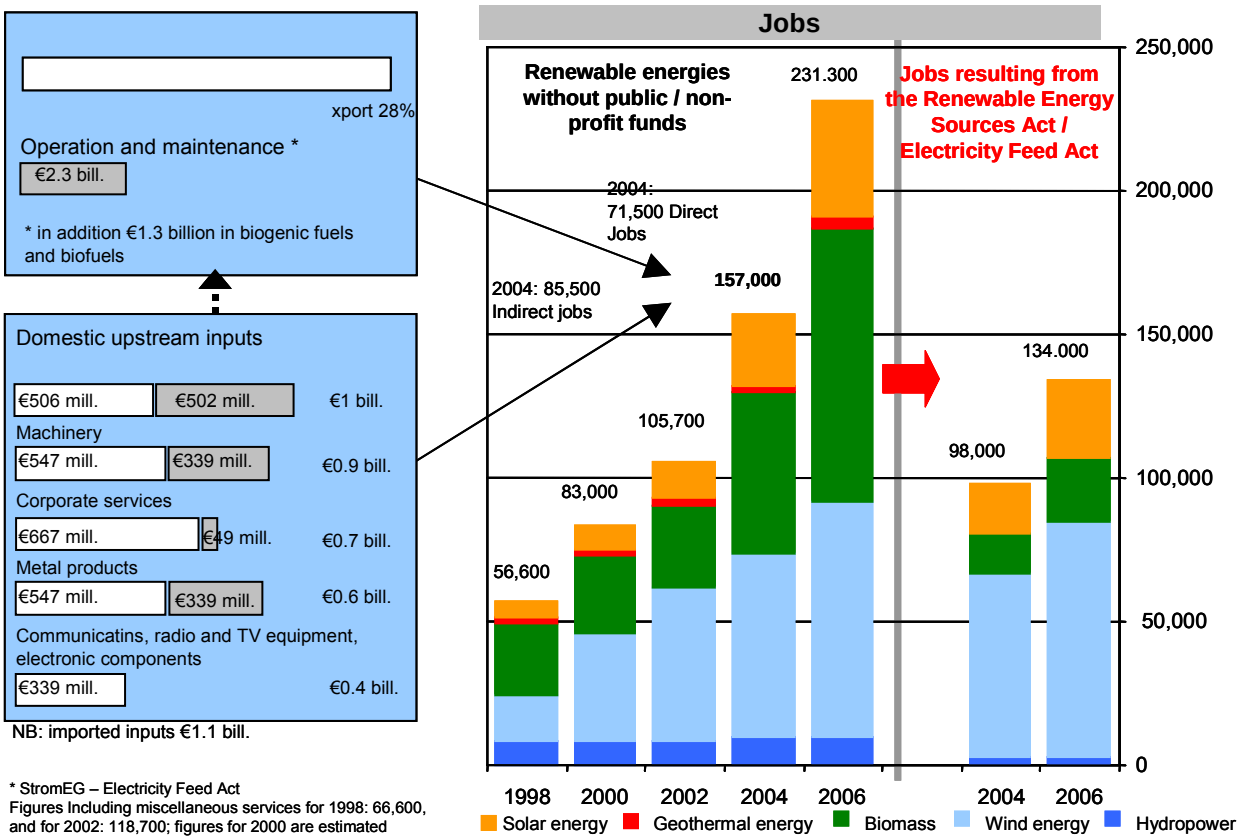


Fig. 4-6: Employment trends in the renewables industry and employment resulting from the Renewable Energy Sources Act / Electricity Feed Act, 1998-2006 [3]

In parallel to these positive employment effects, the renewables expansion has also had some negative impacts on jobs. From an economic perspective, this is mainly due to the budget effect: the additional costs of promoting renewables under the Act at present reduce consumers' purchasing power and, as a knock-on effect, lead to lower demand for goods and therefore job losses in other sectors.

However, it should be noted in this context that the overall balance is positive: there has been a net gain in employment, even taking into account the negative employment effects of renewables expansion. According to recent studies, the net employment effect in 2006 amounted to between 67,000 and 78,000 jobs [**3**].

Overall, however, it must be borne in mind that the jobs created in the renewables sector are highly dependent on the competitiveness of the individual technologies, and therefore also on promotion conditions.

4.5 The EEG in the European and international context

In total, 18 EU Member States have now established payment schemes for the feed-in of RE electricity (Fig. 4-7). The European Commission has also stated that such schemes are very effective and achieve a high degree of economic efficiency, especially in promoting wind energy [15]. At present, feed-in regulations for renewable energy exist in over 40 countries, with fees being paid for electricity fed in from various renewable energy sources.

Overall, by far the largest number of wind farms has been built in countries in which a feed-in payment scheme similar to the Renewable Energy Sources Act exists, or existed, for renewable-generated electricity. In 2006, Denmark, Spain and Germany alone accounted for around 35,370 MW of installed capacity – almost 73% of the EU-25's total wind energy capacity (48,027 MW) and a good 48% of the wind energy capacity installed worldwide (74,223 MW) [16].

In order to facilitate the transnational exchange of experience between countries with feed-in payment schemes and to enable them to learn from each other and provide other countries with support in introducing or improving similar schemes, the "International Feed-In Cooperation" initiative was launched in 2004. Its current members are Germany, Slovenia and Spain; other members are welcome to join. The initiative runs international workshops and research projects, and has its own website (www.feed-in-cooperation.org) to share ideas and experience and promote the benefits of feed-in payment schemes for RE electricity among policy-makers, the research community and the interested public.

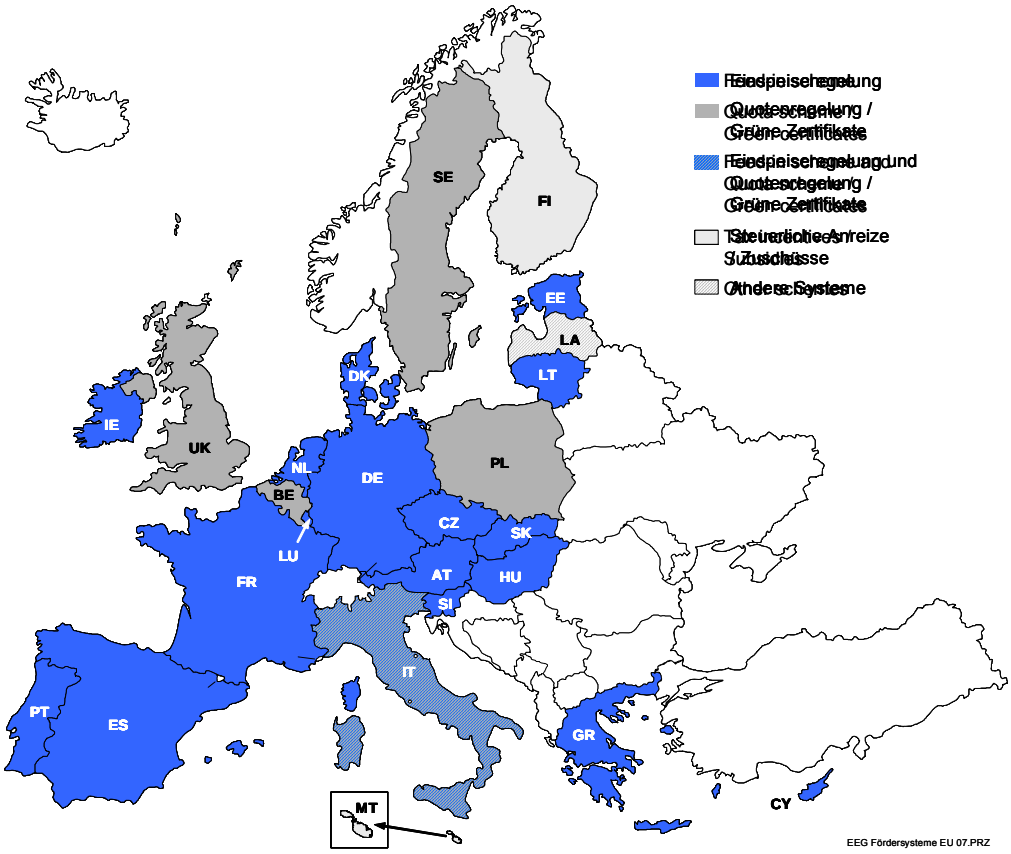


Fig. 4-7: Support schemes for renewables expansion in the European electricity market, 2006 (excluding Romania and Bulgaria, which only joined the EU on 1 January 2007) [17]

A survey carried out by the European Commission in 2006 concludes that 80% of EU citizens are in favour of solar energy. EU citizens are highly positive about the use of other renewable energy sources as well: 71% support the use of wind energy, 65% are in favour of hydroelectric energy, 60% ocean energy (tidal/wave/marine currents) and 55% biomass energy [18]. A survey published by the Federal Environment Ministry in Germany in autumn 2006 contains similar findings [19]. A different picture often emerges, however, when people are directly affected by the construction of biogas or wind energy plants in their neighbourhood: there is often considerable resistance to this type of project. Early consultation with these stakeholders is important in such cases.

5 Cross-Sectoral Aspects

General proviso on funding

During the coming budget years too (2009 and beyond), the expansion of an efficient energy and climate policy must take place in accordance with the Federal Government's budget consolidation objectives, its financial plans as adopted to 2011, and the need for further reductions in the new federal borrowing requirement. The Federal Cabinet will decide on the individual measures to be adopted in this context during its future deliberations on budget planning.

5.1 Joint analytical framework

During the preparation of this Progress Report, particular reference was made to two research projects commissioned by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) and the Federal Ministry of Economics and Technology (BMWi) respectively.

The Federal Environment Ministry (BMU) commissioned a consortium headed by the Zentrum für Sonnenenergie- und Wasserstoff-Forschung Baden-Württemberg (Center for Solar Energy and Hydrogen Research Baden-Württemberg – ZSW) in Stuttgart and comprising Fichtner AG (Stuttgart), Deutsche WindGuard GmbH (Varel), Institut für ZukunftsEnergieSysteme (Institute for Future Energy Systems), Saarbrücken, GtV-Service GmbH (Geeste), Internationales Wirtschaftsforum Regenerative Energien (International Economic Platform for Renewable Energies), Münster, Wuppertal Institut für Klima, Umwelt, Energie GmbH (Wuppertal Institute for Climate, Environment and Energy), Wuppertal and Bosch und Partner GmbH (Hanover). This project's second interim report was produced in summer 2007 and was made available to the ministries concerned for their internal use; the final report is forthcoming [**1**].

The other project, commissioned by the Federal Ministry of Economics and Technology (BMWi), involved the Institut für Energetik und Umwelt (Institute for Energetics and Environment) Leipzig and Prognos AG (Berlin). Its report was published in November 2006 [14].

The methodology and findings of these studies, which form the basis for the Progress Report, differ in several respects. Their methodologies, basic assumptions and findings are therefore presented in parallel in the Annex (Chapter 15.1).

5.2 Feed-in management

At times of high electricity feed-in from renewable energy systems, mainly when there is strong wind, grid bottlenecks are increasingly occurring in some regions of Germany (see also Chapter 12). The reasons for this lie in the changed generation and trading structure, the lack of grid system optimisation, and delays in the expansion of the distribution and transmission grid. Against this background, the new version of the Renewable Energy Sources Act which entered into force in 2004 provides, in its Article 4, for a system of generation management. The practical implementation of this provision has resulted in the regulation of power flow from wind energy plants, which is increasingly causing financial difficulties for the plant operators concerned. For that reason, generation management

should be replaced by "feed-in management", with a stronger focus on maximising feed-in of electricity from RE systems. Feed-in management does not absolve grid system operators of the obligation to upgrade the grid without undue delay pursuant to Article 4 (2) of the Renewable Energy Sources Act.

Previously, when bottlenecks have arisen, grid system operators have generally implemented generation management by removing RE systems – mainly wind energy plants at present, but increasingly biomass systems as well – completely or partly from their grid in regions with a high proportion of wind-generated electricity.

Due to the steadily increasing use of generation management in some regions and the revenue losses that this entails, it is becoming increasingly difficult to finance RE systems, because it is impossible or very difficult to predict the frequency of use of generation management with any certainty. This poses a major obstacle to investment in the continued expansion of renewables in regions with existing or anticipated grid bottlenecks and is putting the Federal Government's renewables expansion targets and therefore also its climate protection targets at risk. In light of this situation, there is clearly a need for policy action here.

An appropriate regulation must aim to maximise the share of renewable-generated electricity being fed into the power grid while maintaining grid security in line with the Energy Industry Act (*Energiewirtschaftsgesetz* – EnWG), without impeding the rapid upgrading of the grid that is prescribed in law. Against this background, the existing provisions on feed-in management contained in the Renewable Energy Sources Act should be optimised. The revision of the provisions on feed-in management must aim to increase transparency and the legal, planning and investment security for operators of RE systems and existing CHP plants, as well as for grid system operators. The current reporting obligations pursuant to Article 12 (3a) of the Energy Industry Act are also important in this context.

The further development of feed-in management should, in particular, be based on full exploitation of all economically viable optimisation options for grid operation, using best available technologies, by grid operators. In particular, it is important to determine which optimisation measures can be applied in the short and medium term (e.g. temperature monitoring of overhead lines, high-temperature conductors).The grid upgrading required in parallel here must be further expedited via the Infrastructure Planning Acceleration Act (*Infrastrukturplanungsbeschleunigungsgesetz*). To this end, RE plant operators should be obliged to ensure that their systems can be regulated by remote control by the grid operator in the event of grid bottlenecks; this may entail an obligation to introduce appropriate technical equipment in the plants, but may also require the introduction of penalties in the event that an RE plant cannot be regulated when grid bottlenecks occur. For RE plant operators who are particularly affected by feed-in management, it is important to determine whether a special equalisation scheme should be established in order to safeguard the funding for new projects as well as the efficient use of feed-in management by the grid operator. Finally, plants whose installed capacity falls below a de minimis limit of 100 kW_{el} should be exempt from the provisions on feed-in management in order to ensure that small-scale systems, especially those operated by private individuals, are not unduly burdened.

Policy recommendations on feed-in management

Provisions within the scope of the Renewable Energy Sources Act

- Feed-in management to involve the use of all economically viable opportunities for grid optimisation using best available technologies.
- Mandatory use of technologically optimised feed-in management, starting with those RE plants which can be expected to have the greatest impact in safeguarding (n-1) security. The aim of technologically optimised feed-in management is to safeguard grid security at the lowest possible commercial and macroeconomic cost while maximising feed-in from RE plants
- Obligation of RE plant operators to ensure that their systems can be regulated by remote control by the grid operator in the event of grid bottlenecks. In the interests of economic rationality, it is important to determine whether existing small biomass-CHP system can be exempted from this requirement.
- Exemption from feed-in management for plants whose installed capacity falls below a specific threshold (de minimis limit of 100 kW_{el}).
- Transparent structuring of feed-in management between grid system and plant operators, also prior to application.
- Introduction of an appropriate hardship scheme to be considered for RE systems operators whose energy output would be affected by feed-in management to a particularly high degree. In this context, it is also important to determine why no such agreements have yet been established between plant and grid system operators.

Flanking measures outside the scope of the Renewable Energy Sources Act

- Introduction of identical provisions in the Act on Combined Heat and Power Generation (*Kraft-Wärme-Kopplungsgesetz* – KWK-G).

5.3 Availability of data on renewables expansion and the work of the Federal Network Agency (BNetzA)

For reporting and decision-making on policy measures, a good data basis is essential. Due to the rapid development of the renewable energy industry and the large number of small and medium-sized plants, producing a comprehensive and up-to-date data basis is a relatively complex task. At present, the data basis in the individual sectors varies in quality and is inadequate across the board, especially as regards data about the number of plants and their capacity, locations and output, and – in the case of biomass and geothermal energy – heat and power cogeneration and the energy efficiency of the systems concerned. The situation is also unsatisfactory as regards data on the impacts of renewable energy systems on nature and landscape, especially for hydropower and biomass, and including agricultural statistics.

The work of the Federal Network Agency (BNetzA) to date, based on the revised Renewable Energy Sources Act of 7.11.2006

The Federal Network Agency (*Bundesnetzagentur* – BNetzA) undertakes regulatory activity in the field of energy and gas supply grids falling within the scope of its jurisdiction. The legal framework for these tasks is the Second Act to Amend the Energy Industry Act, which entered into force on 13 July 2005. On the basis of the competences assigned to it in the First Act to Amend the Renewable Energy Sources Act of 2006, the Federal Network Agency monitors compliance by the grid system operators and electricity supply companies, and the associations formed by them, with their obligations pursuant to Article 5 (2) and Article 14a of the renewable Energy Sources Act. However, in line with the explanatory memorandum to the First Act to Amend the Renewable Energy Sources Act, there are only grounds for monitoring in the case of non-compliance. Only in such a case can the powers of investigation and, if necessary, the enforcement of lawful action be exercised.

To this end, however, it is essential that the Agency – whose previous work focussed on very different areas of economic network regulation, unbundling, network access and monitoring of use-of-system charges – should establish a data structure in order to be able to intervene when necessary. Against this background, the Agency is currently setting up a comprehensive and informative database, with initial findings due in 2007. The fulfilment of these tasks will in particular equip the Agency with the capability to monitor the balance nationwide between energy amounts and fee payments and to intervene if abuse occurs.

The Federal Network Agency: Its tasks and competences

The transfer of responsibilities to the Federal Network Agency is justified in Bundestag Printed Paper 16/2455, p. 7, as follows:

> "The Renewable Energy Sources Act is as a matter of principle not executed by public agencies but regulates the legal relationship between private persons under civil law. Empirical experience gained over the last five years has shown that due to the varying status of the private energy industry actors falling within the scope of the Renewable Energy Sources Act, the possibility that infringements of the law could occur during the implementation of the Act, especially as regards the passing on of ensuing costs to the final consumer, cannot be ruled out and cannot be adequately addressed with the instruments currently available under civil law."

Pursuant to Article 19a (1) of the Renewable Energy Sources Act, the Federal Network Agency is therefore assigned a nationwide and exclusive responsibility to monitor that:

1. the electricity supply companies only receive remunerations pursuant to Article 5(2) of the Renewable Energy Sources Act, minus the network charges that were avoided,
2. system operators and electricity supply companies fulfil their data disclosure requirements pursuant to Article 15 (2) of the Act and their obligation to transmit data to the Federal Network Agency under Article 14a (8) of the Renewable Energy Sources Act,
3. third parties are only informed of the actual differential costs pursuant to Article 15 (1), first sentence of the Renewable Energy Sources Act.

In order to perform these tasks, the Agency must monitor the mechanism determining the balance of electricity volume and remuneration across Germany. To enable the Agency to fulfil its monitoring obligations, pursuant to Article 14 (8) of the Renewable Energy Sources Act, grid system operators and utility companies must submit their final accounts to the Agency in electronic format by 30 April 2007.

The Agency's approach

The Federal Network Agency started its preparations for data collection in autumn 2006. This then began from January 2007 with the collection of master data about the electricity supply companies (company name, location, legal status, name of contact person, etc.) covered by the purchase obligation under the Renewable Energy Sources Act. Each company was then given an ID number and access rights to a system of secure communication with the Federal Network Agency.

The Agency's IT infrastructure has been adapted overall so that not only grid system operators can transmit corporate data securely via the Agency's energy data portal; the electricity supply companies can now do so as well.

As of June 2007, some 900 grid system operators and around 1000 electricity supply companies with an obligation to purchase RE electricity were registered with the Agency. These operators and suppliers have a duty to furnish information and are surveyed by the four transmission grid operators using questionnaires.

In order to make the task of surveying as practical as possible, the Agency conducted an intensive dialogue with the relevant associations in advance of the data collection. Sample questionnaires, together with explanatory definitions of the required data, were published on the Agency's website for electricity supply companies and grid operators respectively on 10 April 2007.

During the first round of data collection, all grid system operators and electricity suppliers were required to transmit the data for the 2006 calendar year and up to 30 April 2007 to the Agency electronically via its energy data portal. However, the data submitted by this deadline were far from complete.

Problems arose in connection with the legal deadline for the transmission of data by grid system operators and electricity supply companies. This ends on 30 April in the subsequent year. However, many companies did not have final audited data available for the period in question, with the result that only provisional data were supplied by the cut-off date, with audited data being submitted during the following months. The process of data collection and verification has still not been concluded.

Using the EEG questionnaire, the grid operators are required, *inter alia*, to state the amount of electricity fed in under the Renewable Energy Sources Act, with precise details of categories and energy carriers used. These data must be provided by the plant operators to the grid operators. The relevant remuneration paid must also be stated. Similarly, the grid utilisation charges avoided as a result of the feed-in must also be stated; these are deducted from the remuneration paid to the grid operator. Data are also collected on the number of plants, their capacity, and the installed capacity eligible for remuneration under the Renewable Energy Sources Act, the type of energy carrier used, and the year of commissioning.

Electricity suppliers are required to state the overall non-priviliged and privileged end-consumer power sales, broken down according to grid operators. In addition, they must state, among other things, the quantity of EEG-remunerated electricity sold during the year via fixed monthly advances, and the quantity of EEG-remunerated electricity to be purchased/compensated for previous periods on the basis of annual equalisation, and the payments made for this.

The data transmitted to the Agency for the calendar year 2006 are evaluated internally to verify their accuracy. In this context, the data supplied by the transmission grid operators is also referred to; this must be received by the Agency no later than 30 September 2007.

Using the findings, the Agency is then able to verify whether the information published by the grid operators and electricity supply companies on their websites genuinely conforms with the law. If necessary, a check can also be carried out to determine whether the differential costs identified for third parties are in line with the provisions of Article 15 (1) of the Renewable Energy Sources Act.

In view of the short run-up to the first round of data collection, a semi-automated survey and evaluation of the data took place using Excel spreadsheets. A priority in the Agency's current work is to develop the requisite infrastructure to provide market participants with fully automated data collection in 2008, thus making data transmission easier.

It should be noted that during the one-year development period, no specific cases of misuse or complaints were made in relation to the Federal Network Agency. In order to handle the development of the database and the start of data collection, around eight members of staff have been employed by the Agency during the start-up phase, instead of the usual 3-5 provided for in the explanatory memorandum to the First Act to Amend the Renewable Energy Sources Act. It can be assumed that similar staffing levels will be required during the coming years; this will be decided in the relevant budget procedure.

Policy recommendations on data availability

Provisions within the scope of the Renewable Energy Sources Act

- The Federal Network Agency will collect and process the data defined in the Renewable Energy Sources Act and required as a basis for remuneration of RE electricity fed in under the Act.

5.4 Principle of exclusive use

The principle of exclusive use is enshrined in Article 5 of the Renewable Energy Sources Act. It ensures that plants which use both fossil and renewable energies are not entitled to remuneration under the Act. As this area of hybridisation with fossil fuels is adequately covered by greenhouse gas emissions trading in the relevant areas of application, it is sensible to retain this principle of exclusive use.

By contrast, the use of a mix of renewable sources in a single plant should be eligible for remuneration under the Act. Examples are the combination of a biomass facility with a geothermal plant or a system for the generation of electricity from solar radiation. The combined use of biomass recognised under the Biomass Ordinance with landfill and sewage gas or other materials which, due to their biogenic origin, can be regarded as biomass but are not defined as biomass in the Biomass Ordinance or qualify for remuneration under the Renewable Energy Sources Act, should also be facilitated. These energy mixes can increase the energy efficiency of the facility while contributing to more constant or regulatable electricity production. These types of hybrid systems are technologically feasible today and are desirable in terms of improving the integration of renewable-generated electricity into the energy supply system. They should therefore become eligible for funding under the EEG (see Chapter 12).

In order to allow a mix of renewable sources while retaining the remuneration obligation under the Act, the principle of exclusive use must be elaborated in more detail in Article 8 of the Renewable Energy Sources Act. This should ensure, firstly, that only the use of biomass which falls within the scope of the Biomass Ordinance is remunerated under Article 8 of the Act. Secondly, a mix of this biomass with other renewables and, indeed, with biomass which does not fall within the scope of the Biomass Ordinance but only within the sphere of application of Article 3 of the Renewable Energy Sources Act must be possible and remunerated accordingly on a pro rata basis.

The principle of exclusive use should also be elaborated in relation to the use of operating resources which have a neutral effect on remuneration under the EEG and increase the efficiency of the plants or improve biogas yield. This should be made clear in the explanatory memorandum to the Renewable Energy Sources Act.

The principle of exclusive use should be made more flexible for biogas plants which are eligible for the NawaRo bonus. It should in future be permissible to use specific plant by-products which are not eligible for the NawaRo bonus together with biomass which is eligible for this bonus. This should be based on a positive list. However, fees for the electricity generated from biogas should only apply to the NawaRo share.

Moreover, in elaborating the principle of exclusive use, it is important to determine whether other regulations must be amended in order to allow a mix of different renewables to be used. For example, it may be appropriate to include provisions on the classification of electricity to the various renewable energies in Article 5 of the Renewable Energy Sources Act.

It is also important to ascertain, in the definition of systems contained in Article 3 (2) of the Renewable Energy Sources Act, whether hybrid systems consist of one or several facilities.

Policy recommendations on the principle of exclusive use

Provisions within the scope of the Renewable Energy Sources Act

- The principle of exclusive use to be elaborated, making payment of fees for electricity generated from a mix of renewable sources more straightforward while continuing to exclude electricity generated from a mix of renewable and non-renewable energies from eligibility for remuneration.
- The principle of exclusive use to be elaborated in order to make the use of operating resources which are intended to increase the efficiency of the plant and biogas yield neutral in terms of the impact on eligibility for remuneration and bonuses under the Renewable Energy Sources Act.
- The principle of exclusive use should become more flexible as an incentive to generate electricity from hitherto untapped biomass potential (definitive list) without calling the status of facilities into question as a matter of principle.
- Clarification in the Renewable Energy Sources Act: the admixture of fossil gas in biogas in order to meet quality standards for the feed-in of biogas into the natural gas grid should not affect eligibility for remuneration under the Act.

5.5 Prohibition of multiple sale and separation from other instruments

Pursuant to 18 (1) of the Renewable Energy Sources Act, electricity produced from renewable energy sources may not be sold more than once. Pursuant to Article 18 (2) of the Act, plant operators who have already received payment for the electricity produced in their plants may not forward any guarantees for electricity produced from renewable energy sources.

Emissions trading

Within the framework of emissions trading, Article 2 (5) of Germany's Greenhouse Gas Emissions Allowance Trading Act (*Treibhausgas-Emissionshandelsgesetz* – TEHG) of 8 July 2004 (Federal Law Gazette I, p. 1578) takes account of these provisions: plants covered by the Renewable Energy Sources Act fall outside the scope of the TEHG. This means that no "multiple sale" can take place within the framework of emissions trading.

Facilities which burn biomass together with other materials are included in emissions trading, however. This co-incineration is not eligible for remuneration under the Renewable Energy Sources Act, as the Act only covers facilities which generate electricity solely from renewable energies. Under Annex 2 of the TEHG, the emissions factor for biomass is zero. With co-incineration, the biomass fraction must therefore be identified and properly documented.

In the adoption of legislation for the 2008-2012 trading period, emissions trading and the Renewable Energy Sources Act will remain separate: facilities which have a legal entitlement to remuneration under the Renewable Energy Sources Act will, pursuant to the new Article 2 (5) TEHG, continue to fall outside the scope of the TEHG. As the law stands, fossil-fuel power plants which co-incinerate biomass are not eligible for remuneration under the Renewable Energy Sources Act, but are entitled, therefore, to emissions trading allowances. This rule should be retained.

The allocation of allowances to energy installations will be switched from a system based on past emissions to a benchmarking system. In the draft Allocation Act 2012 (*Zuteilungsgesetz* 2012 – ZuG 2012) adopted by the Federal Cabinet, two separate benchmarks were established for electricity generation systems: 365 g/kWh for the use of gaseous fuels, and 750 g/kWh for the use of other fuels. In future, then, biomass facilities covered by emissions trading (i.e. those with a thermal output above 20 MW and no eligibility for remuneration under Article 5 (1) of the Renewable Energy Sources Act) will be allocated allowances in line with these benchmarks. As the emissions factor for biomass will continue to be zero, however, no allowances will need to be used, allowing the allowances allocated to be traded in the marketplace.

CDM and JI

With the new project-based Kyoto mechanisms, the Clean Development Mechanism (CDM) and Joint Implementation (JI), and especially with the provisions of the Project Mechanisms Act (*Projekt-Mechanismen-Gesetz – ProMechG*) [20], new financing options have been introduced. As the law stands, these options are also available in principle to facilities covered by the Renewable Energy Sources Act: from a purely legal perspective, systems which are remunerated under the EEG can – under certain conditions – also qualify as JI projects pursuant to Article 5 of the Project Mechanisms Act and can thus be allocated emissions allowances, which they can then sell. For the current period, applications for allowances have been lodged for a number of mine gas projects, for example.

This parallel use of the two types of instrument does not conform with the intentions of the Renewable Energy Sources Act. Remuneration under this Act is intended, on principle, to enable RE plants to operate on a commercially viable basis.

A new funding mechanism is not required; however, if such a mechanism existed, it would have to be taken into account when setting appropriate remuneration. This issue is not addressed in the present Progress Report. As the parallel use of the two instruments does not conform with the true intentions of the EEG, it is recommended that explicit provisions be introduced in both in the Renewable Energy Sources Act and in the ProMechG to close this loophole.

Policy recommendations on the prohibition of multiple sale and separation from other instruments

Flanking measures outside the scope of the EEG

- Recognition of a plant as a JI project under Article 5 ProMechG to be ruled out if it is eligible for remuneration under the Renewable Energy Sources Act. However, a plant may be recognised as a JI project (assuming that it meets the criteria set out in ProMechG), if, prior to the commissioning of the plant, any entitlements to remuneration under the Renewable Energy Sources Act are permanently renounced.

6 Electricity from Hydropower (Article 6 EEG)

The 2004 revision of the EEG introduced two significant changes in terms of the fees paid for electricity from hydropower. Firstly, the ecological criteria for the use of small-scale hydropower in particular were increased; secondly, hydropower plants with an installed capacity of over 5 MW were included in the remuneration system for the first time.

Since the revision of the EEG, when a plant of up to 500kW is modernised, and as of 1 January 2008 when such a plant is first constructed, it must be proven that the use of hydropower achieves good ecological water status or that there have been significant improvements in the existing status (Table 6-1). The main ecological requirement/criterion is that plants licensed after 31 December 2007 may only claim payment under the EEG if they are constructed in the spatial context of a barrage weir or dam. The Federal Environment Ministry has published guidelines on fees paid for electricity from hydropower. These recommend measures which, if implemented, would ensure the improvements in water ecology required by the EEG. For small-scale plants in particular, the increase in fees from 7.67 cents/kWh to 9.67 cents/kWh provides the incentive necessary for realising these ecological improvements for plants with a capacity up to and including 500 kW.

Medium-capacity plants up to and including 5 MW which were commissioned before 1 August 2004 and were later modernised within the meaning of Article 21(1) No. 2 EEG may switch to the higher fees for their capacity up to and including 500 kW provided they fulfil the ecological requirements/criteria. Under the 2004 EEG, the ecological requirements/criteria do not apply to newly constructed plants with a capacity of between 500 kW and 5 MW.

The 2004 revision of the EEG also brought run-of-river power plants with a capacity of between 5 and 150 MW into the EEG payment system for the first time, provided they are commissioned prior to 31 December 2012. In the case of modernisations or expansions, an increase in the electrical energy of at least 15% must result. The payment entitlement relates to the quantity of energy harnessed additionally as a result of the modernisation. Compliance with the ecological criteria is a precondition for eligibility for payments under the EEG for plants in this capacity range as well.

The payment system for hydropower differs in two respects from those for the other renewable energy sectors. The first difference is that no degression was introduced for plants of up to 5 MW, as there is no potential for cost-cutting here. The second is that the remuneration periods depend on the size of the plant and the year it was commissioned (see Table 6-1). There is no time limit on payment claims for existing plants commissioned prior to 1 August 2004. For plants of up to 5 MW, the limit according to the 2004 EEG is 30 years; for plants of over 5 MW it is 15 years.

Table 6-1: Key rules in the Renewable Energy Sources Act on payment for electricity from run-of-river hydropower [6]

	Existing plants of up to 5 MW (commissioned before 1.8.2004)		**Existing plants of up to 5 MW (commissioned before 1.8.2004, modernised after 1.8.2004)**		**New plants of up to 5 MW (commissioned in 2007)**		**New or modernised plants from 5 MW to 150 MW (commissioned in 2007)** (Figures for plants commissioned in 2004 in brackets)	
	Capacity	Fee in ct/kWh	Capacity	Fee in ct/kWh	Capacity	Fee in ct/kWh	Capacity	Fee in ct/kWh
Minimum fee	Up to 0.5 MW 0.5 – 5 MW	7.67 6.65	Up to 0.5 MW 0.5 – 5 MW	9.67 6.65	Up to 0.5 MW 0.5 – 5 MW	9.67 6.65	Up to 0.5MW 0.5 – 10 MW 10 – 20 MW 20 – 50 MW 50 – 150 MW	7.43 (7.67) 6.44 (6.65) 5.92 (6.10) 4.42 (4.56) 3.58 (3.70)
Remuneration period	No time limit on eligibility		30 years + year of commissioning (time limit placed on previously unlimited eligibility period)		30 years + year of commissioning		15 years + year of commissioning	
Degression for newly commissioned plants	----		----		----		1% p. a. from 1.1.2005	
Particular requirements	----		Proof of either good ecological status of body of water or of a substantial improvement compared to the previous status in the form of the authorisation under water law		Proof of either good ecological status of body of water or of a substantial improvement compared to the previous status in the form of the authorisation under water law for new plants of up to 500 kW licensed from 1.1.2008		• Proof of either good ecological status of body of water or of a substantial improvement compared to the previous status in the form of the authorisation under water law • An increase of at least 15% in electrical energy • Commissioned by 31.12.2012	

6.1 Market development and electricity production costs

As the potential of hydropower has already been tapped to a relatively high degree, this sector is less dynamic at present than the other renewable energy sectors (Table 6-2). Due to the insufficient availability of data, it is not possible to give precise details of developments in capacity installed. However, it can be assumed that only a relatively small amount of additional capacity (around 20 MW a year) has been added recently through new construction, repowering and modernisation, and that only a small proportion of plants with a capacity up to and including 5 MW has been modernised in a way which achieves improvements in water ecology.

The inclusion of plants with a capacity of over 5 MW in the 2004 EEG has supplied the impetus for several projects. Of these, the following three are particularly significant:

- the Rheinfelden power plant, which is deemed to be a new construction (100 MW, approx. 450 million euros in investment, commissioning planned for 2010/2011),

- the new construction of a hydroelectric power plant on the river Weser near Bremen (10 MW, approx. 27 million euros in investment, commissioning planned for 2009),
- the expansion of the Franco-German Iffezheim power plant on the Rhine (approx. 38 MW, approx. 70 million euros in investment, commissioning planned for 2011).

Once these plants come on-stream, the additional electricity generated is likely to be in the region of 700 GWh a year. This shows that the legislator's decision to include large-scale hydropower plants in the EEG has provided a useful incentive. However, due to the long planning and licensing timescales, none of these projects has yet been implemented.

Table 6-2: Key features of developments in electricity generation from hydropower between 2003 and 2006, after [1, 2, 3, 4]

	2003	2004	2005	2006
No. of plants			7,356	7,679
Up to 5 MW			7,201	7,524
From 5 MW			155	155
Total installed capacity (MW)	4,640	4,660	4,680	4,700
Up to 5 MW			815	869
From 5 MW			3,466	3,466
Annual new installations (MW/a)	20	20	20	20
Electricity generated from hydropower (GWh/a) subject to EEG payment	4,148	4,616	4,953	4,924
Electricity generated from hydropower (GWh/a) not eligible for EEG payment	16,202	16,384	16,548	16,897
EEG payments (million €/a)		334.5	355.99	366.56
EEG fee (in cents/kWh)		7.25	7.19	7.44
Total reduction in CO_2 emissions (in million tonnes/a) due to hydropower	22.1	22.9	23.4	22.5
Of which reduction in CO_2 emissions (in million tonnes/a) due to hydropower subject to EEG payment	4.5	5.0	5.4	5.2
Jobs[1)]		Approx. 9,500	No data	Approx. 9,400

1) includes hydropower outside the scope of the EEG; 2005 figure
Where table incomplete, no figures available

The results of the economic viability calculations performed show that the new construction of micro hydropower plants of under 100 kW in particular, but also of plants between 100 kW and 5 MW, is only worthwhile under favourable conditions, even with existing transverse structures.

In the 100 to 1,000 kW capacity range, typical specific investment costs for new construction can be assumed to be around €5,000/kW and full load usage around 3,000 – 5,000 hrs/a (Fig. 6-1). New construction is therefore normally only economically viable (on the basis of EEG payments alone) in particularly advantageous locations. Only where circumstances are particularly favourable, (if full load usage is over 5,000 hrs/a and specific investment costs can be kept to between €4,000 and €4,500/kW due to very favourable local conditions), is it economically viable to repower and modernise smaller plants.

It should be noted as a general point with regard to the new construction and modernisation of hydropower plants that cost advantages arise from increased plant size due to decreased specific investment. Thus for larger plants (which can also usually assume more hours at full load) in favourable locations even new construction may be economically viable.

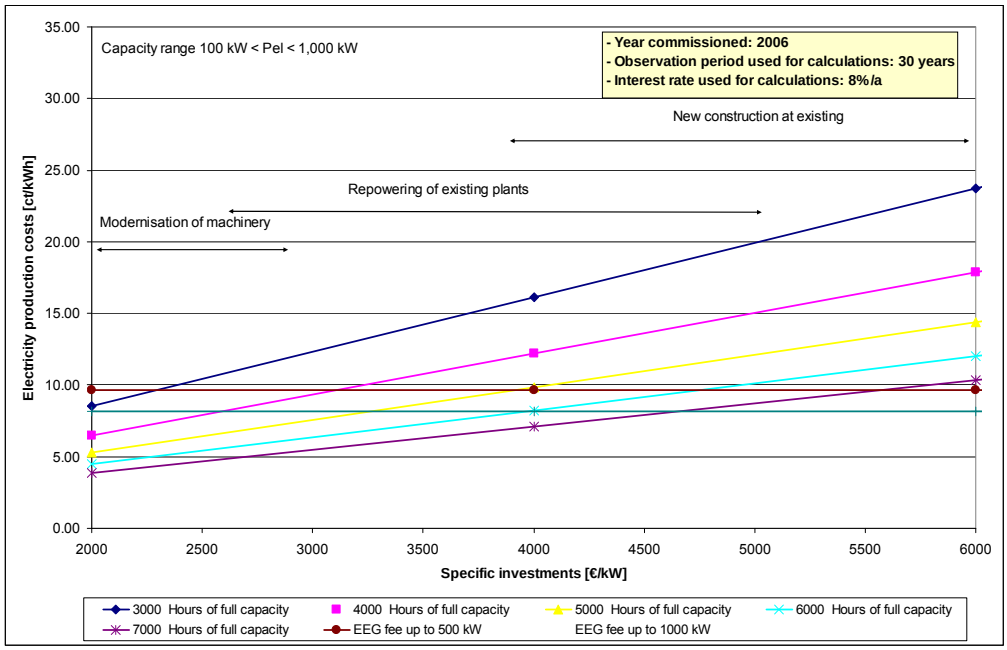


Fig. 6-1: Reference figures for electricity production costs at hydropower plants with a capacity of between 100 and 1000 kW, after ZSW et al. 2007 [1]

Electricity production costs depend on plant size, and are set against EEG payments (see Fig. 6-2). An average investment cost of €5,000/kW was assumed for a 50 kW plant, and €3,000/kW for a 20 MW plant; the assumption was for 3,000-4,500 hrs/a at full load.

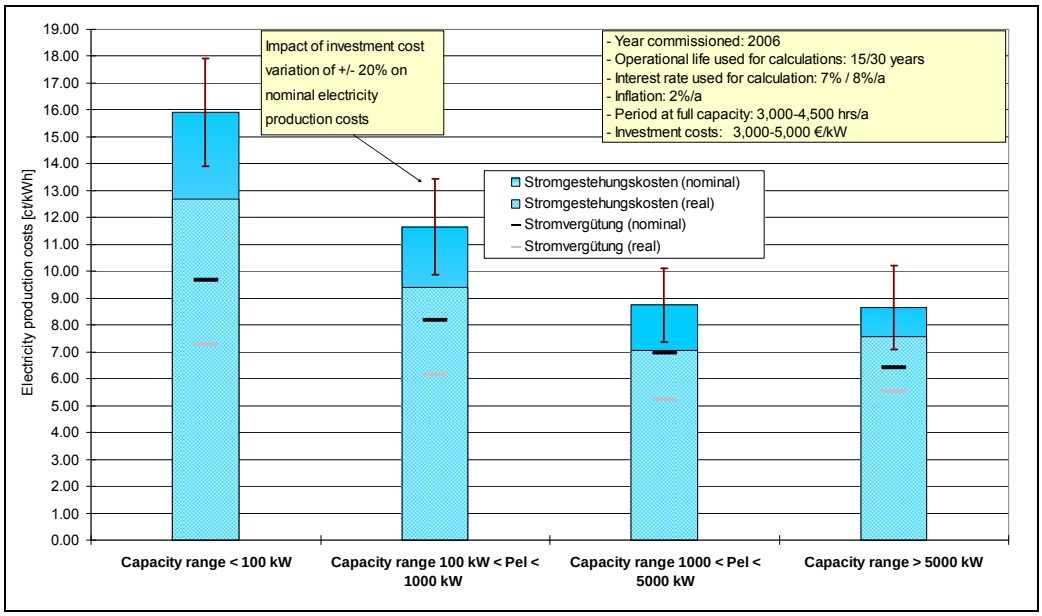


Fig. 6-2: Reference figures for real and nominal electricity production costs for new plants (commissioned in 2006) as against the mid-rate of payment (real and nominal) for hydropower plants, after ZSW et al. 2007[3] [1]

[3] The costs are shown in real terms, i.e. adjusted for inflation, and as nominal figures without considering inflation. As the remuneration rates under the EEG are nominal figures, these should be compared to the nominal electricity production costs. For completeness, inflation was also included on the income side (real payment). Real electricity production costs should therefore be compared with real payments and nominal electricity production costs with nominal payments. (See also Chapter 15.1 page 163 ff.)

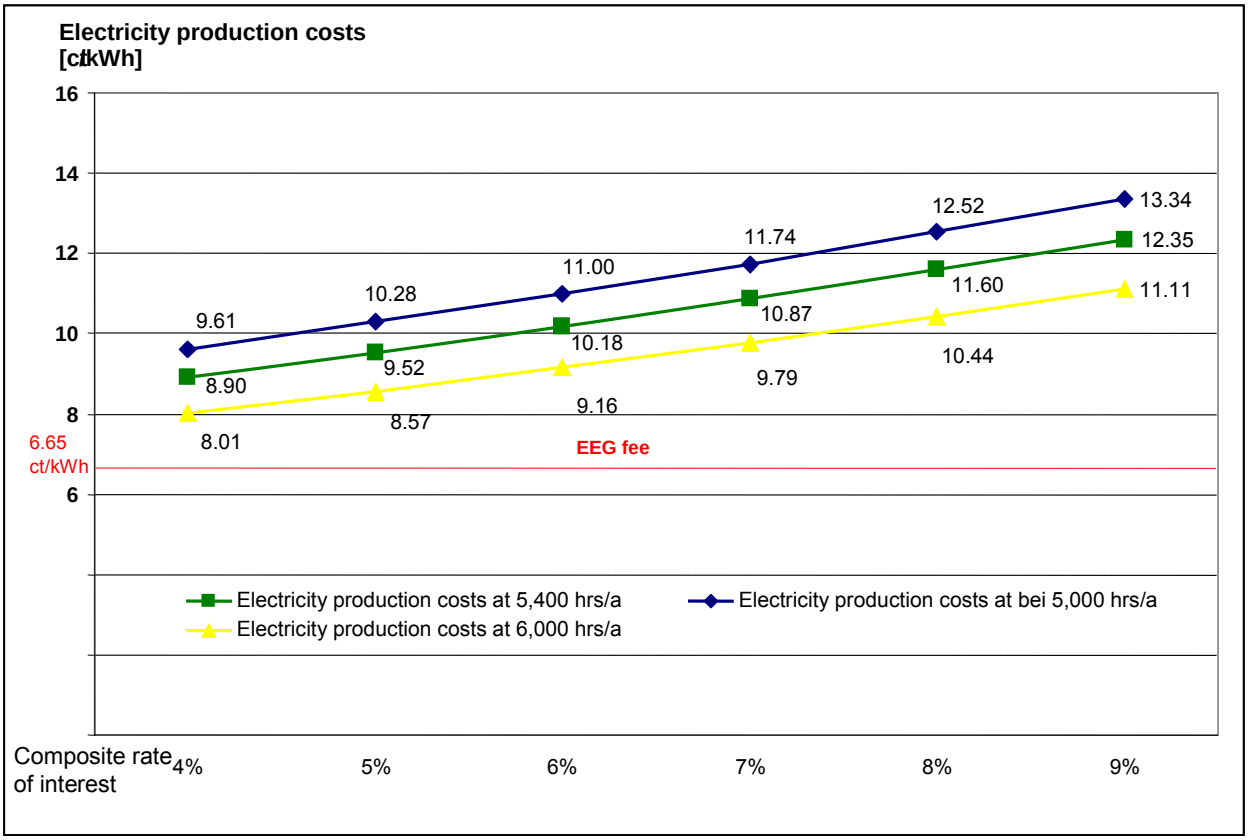


Fig. 6-3: Electricity production costs for 2.5 MW hydropower plants depending on the interest rate, in cents/kWh, after IE/Prognos 2006 [14]

Fig. 6-4 clearly shows that later improvements in ecological status, especially those involving investment measures, often result in additional electricity production costs. In favourable circumstances, these can be covered by the additional 2 cents/kWh payable in EEG fees [1].

Thus the incentive destined for measures which improve ecological status, namely 2 cents/kWh for plants of up to 500 kW or for a larger plant's capacity up to 500 kW, permits a maximum (additional) investment of €1,500/kW – and only if we assume a very high 7,000 hours at full load. For the majority of plants, with between 4,000 and 5,000 hours at full load, investment would be limited to €800 – €1,000/kW. For small plants in particular, this level of additional income could only achieve an improvement in the minimum water discharge. Furthermore, Fig. 6-4 does not consider the profit forfeited in conjunction with the minimum water discharge requirements usually imposed in the context of the measures taken to achieve ecological status improvements.

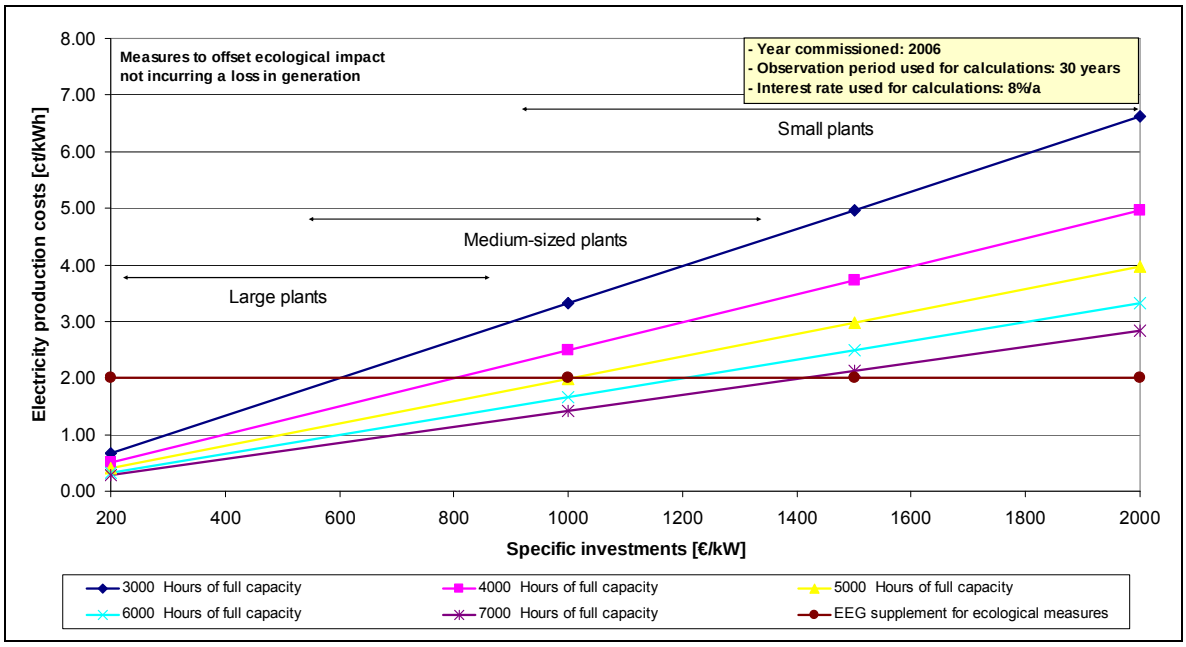


Fig. 6-4: Reference figures for additional electricity production costs incurred by the implementation of ecological adaptation measures as against the EEG bonus granted, after ZSW et al. 2007 [1]

From the above we can conclude that, under present conditions, the EEG supplies effective incentives for the modernisation and revitalisation/renewal of large hydropower plants. When smaller hydropower plants are modernised, investment measures aimed at ecological water status improvements are economically viable due to the increased EEG fee – but only under favourable conditions. In contrast, the new construction of small plants would only be possible with a significant increase in the fee payable. In order for the increase in fees to act as an incentive as the legislator intended, the increased fees should only be granted where the plant's ecological compliance is assured.

The EEG treats ocean energy systems as a special type of hydropower. Plants that harness the power of flows/currents, waves, salt and temperature gradients are therefore eligible for EEG payments for electricity from hydropower. However, current levels of specialist knowledge dictate that harnessing the power of the ocean will only be economically viable in a few parts of the German North and Baltic Sea waters. Nevertheless, the world's oceans hold great potential and other countries will be making increased use of this type of energy system in the medium to long term, once it has become economically viable to do so. This is therefore a market with future potential, especially in terms of export opportunities for German companies and research institutions.

To date, no ocean energy systems exist in Germany. Internationally, only initial demonstration and pilot plants have been installed. The relevant technology is therefore currently at the research and development stage, with German plant construction companies and research institutes strongly involved. The current situation means that it is not yet possible to supply reliable predictions/forecasts for investment and operating costs.

6.2 Environmental evaluation of provisions under the EEG

When hydropower plants are first constructed, modernised or renewed, proof is needed that they have achieved good ecological water status or that the current status is a significant improvement on the previous status. For the purposes of practical implementation, the Federal Environment Ministry – on behalf of the Environment Committee of the Bundestag – has published guidelines which were developed in agreement with hydropower operators' and nature conservation associations [21]. These guidelines contain recommendations for action on biological continuity for up- and downstream migrating species (such as using fish ladders), on minimum water discharge and on the management of water reservoirs. The guidelines have ensured that, for the first time, a single, transparent set of criteria is available for the environmental assessment of hydropower plants. The guidelines have met with a good response among authorities, planners and operators. Further work should be conducted along these lines in close collaboration with the *Land* enforcement agencies, in order to create further incentives for the ecological modernisation of existing hydropower plants. These should include incentives relating to fish conservation.

Unfortunately, the provision made in the 2004 EEG for achieving improvements in ecological water status by means of requiring an authorisation under water law is not effective in all cases. The authorisation procedure should therefore be redesigned to ensure that it is straightforward to secure compliance with ecological requirements. The obvious approach here would be to firm up the ecological criteria contained in Article 6 EEG in line with the German government's proposal to include new legislative criteria in the Environmental Code (UGB) on managing water resources in the context of authorising hydropower plants. Compliance with these criteria could be demonstrated via a certificate from the authorities explicitly confirming the same, e.g. by means of an appropriately worded authorisation under water law. This would mean uniform federal standards could be used as a basis for the authorisation of hydropower plants, while also ensuring the maximum planning and investment security for plant planners and operators. In a break with the past, the relevant ecological criteria should not only be used for plants with a capacity up to and including 500 kW and those over 5 MW: they should be introduced for hydropower plants of all capacities as a means of strengthening the incentives to improve water ecology.

Hydropower plants commissioned before the 2004 EEG came into force enjoy unlimited payment eligibility. The increase in fees payable for the ecological modernisation of these existing plants – up to 500 kW: 7.67 cents/kWh – has helped to make the market more dynamic.
The ecological criteria apply in a similar manner to plants with a capacity of between 5 MW and 150 MW. It is not currently possible to assess the influence of this on such plants, as only one plant of this capacity has been authorised to date.

6.3 Policy recommendations

We recommend retaining the bulk of the EEG's general provisions for generating electricity from hydropower, making only selected changes. The provisions on electricity from hydropower should be adapted to the scheme used elsewhere in the EEG, and the ecological criteria formulated more precisely. It should be noted that from an economic viewpoint, when it comes to building new plants of up to 5 MW in capacity, the fees payable only seem reasonable for plants where other circumstances are favourable. Larger-capacity plants are therefore at an advantage due to the lower specific investment required.

In the interests of unifying the law, the 30-year remuneration period for small-scale hydropower plants and the 15-year period for large hydropower plants should both initially be set at 20 years. This will require a fundamental change in the level of fees, essentially raising the fees for small hydropower plants and lowering those for large plants.

Due to the reduction in the remuneration period from 30 to 20 years, we recommend an increase of 1 cents/kWh in the fee payable to plants with a capacity of under 5 MW upon modernisation and repowering. This would give the following fees:

- Up to 0.5 MW: 10.67 cents/kWh
- 0.5 – 5 MW: 7.65 cents/kWh

The electricity production costs for newly constructed plants are far higher than those for modernised or reactivated plants. We therefore propose higher rates of remuneration for new plants of up to 5 MW capacity. We further recommend that the fee levels show a greater differentiation according to plant capacity, and that a new capacity boundary be introduced at 2 MW in the aim of avoiding excessive support for large plants and insufficient support for small plants. Because the costs for new construction are higher than those for modernisation or repowering, we recommend an increase in remuneration, staggered as follows: Plants with a capacity of up to 0.5 MW should receive an increase of 2 cents/kWh and plants of between 0.5 and 2 MW an increase of 1 cents/kWh. New plants of between 2 and 5 MW do not need additional remuneration. However, irrespective of capacity, payments should be increased by a further 1 cents/kWh due to the reduced remuneration period. This would give the following fees for new plants of up to 5 MW:

- Up to 0.5 MW: 12.67 cents/kWh
- 0.5 – 2 MW: 8.65 cents/kWh
- 2 – 5 MW: 7.65 cents/kWh

If the remuneration period for plants of over 5 MW capacity is to be increased from 15 to 20 years, the remuneration rates should be reduced accordingly.

The ecological requirements for newly constructed, repowered and modernised plants should be extended to include the new construction of plants with a capacity of between 500 kW and 5 MW. The water ecology criteria in the EEG and Federal Water Act (WHG) should be elaborated, and later incorporated into the federal provisions on authorisation under water law in the Environmental Code (UGB) relating to minimum water volume and linear continuity of watercourses for hydropower plants.

Proof of compliance with ecological criteria is currently stipulated in Article 6(3) EEG, which requires authorisation under water law. In order both to ensure compliance with water ecology criteria and to avoid unnecessary bureaucracy for operators, Article 6(3) EEG should be amended to state that proof may consist of any official statement (authorisation, certificate, or contract under public law) which explicitly and bindingly confirms compliance with water ecology criteria.

In the case of large-scale hydropower, the lengthy authorisation timescales mean that the 31 December 2012 deadline cited in Article 6(2) EEG for newly commissioned plants of over 5 MW is unhelpful. In order to harness additional potential, even plants which cannot be commissioned until after this deadline should be eligible for EEG payments. The degression will provide sufficient incentive for a rapid implementation of such projects. We therefore propose that the deadline be removed so the additional potential may be harnessed.

Even further potential could be harnessed if the 15% rule for plants with a capacity of over 5 MW were removed. The EEG currently states that only plants which can achieve a 15% increase in capacity upon modernisation may benefit from payment for the electricity generated from this additional capacity. Yet the potential for increasing capacity through modernisation is often a matter of just a few percent. Removing this clause does not risk creating any unintended side-effects, as plants may only claim payment for the additional capacity created.

The 150 MW upper limit for large-scale hydropower could also be removed in the interests of improving the clarity of the law, especially as a lack of suitable sites means that no hydropower plants with a capacity of over 150 MW can be built anyway in the medium to long term.

Furthermore, it is worth checking whether or not the use of resources would be more efficient and targeted, particularly from a water ecology viewpoint, with the introduction of a cross-plant payment system into the EEG for the modernisation of several hydropower plants in a single river basin district. Research is currently under way into the conditions and options for this. The Federal Environment Ministry will then assess the outcome of this project and formulate a draft if appropriate.

Policy recommendations for the provisions on electricity generation from hydropower

Provisions within the scope of the EEG

- Remuneration periods unified at 20 years
- A new fee category and higher fee introduced for new facilities commissioned from 2009:
  Share of capacity up to 0.5 MW_{el} 12.67 ct/kWh (currently 9.67 ct/kWh)
  Share of capacity from 0.5 to 2 MW_{el} 8.65 ct/kWh (currently 6.65 ct/kWh)
  Share of capacity from 2 to 5 MW_{el} 7.65 ct/kWh (currently 6.65 ct/kWh)
- A new fee category and higher fee introduced for revitalised/modernised plants commissioned from 2009:
  Share of capacity up to 0.5 MW_{el} 10.67 ct/kWh (currently 9.67 ct/kWh)
  Share of capacity from 0.5 to 2 MW_{el} 7.65 ct/kWh (currently 6.65 ct/kWh)
  Share of capacity from 2 to 5 MW_{el} 7.65 ct/kWh (currently 6.65 ct/kWh)
- For systems with a capacity of over 5 MW: abolition of the cut-off date, the upper limit of 150 MW and the requirement for modernisation to result in an increase in the electrical energy of at least 15%
- Appropriate proof other than authorisation under water law to be made admissible, provided this constitutes a binding confirmation of compliance with the ecological criteria
- Appropriate decrease in the level of fees for large hydropower plants due to the extension of remuneration period from 15 to 20 years.

Flanking measures outside the scope of the EEG

- Simplification of approval procedure under water law.

Flanking measures inside or outside the scope of the EEG

- Remuneration under the Act for all capacity classes of hydropower plant to be based on clear criteria laid out in the Renewable Energy Sources Act (EEG), Federal Water Act (WHG) and Environmental Code (UGB)
- Development of a strategy to introduce an inter-plant remuneration system for the ecological modernisation of several plants within a single river basin district, for a more efficient, targeted use of resources.

7 Electricity from Landfill, Sewage and Mine Gas (Article 7 EEG)

Since the new EEG came into force in 2004, Article 7 has governed payments for electricity from landfill gas, sewage gas and mine gas. The removal of the limit on physical capacity has meant even large facilities are now covered by Article 7, although electricity produced from mine gas is the only type for which facility capacity in excess of 5 MW is eligible for payment. Another noteworthy feature is the technology bonus which was introduced in Article 7(2). The minimum fees payable increase by 2.0 cents/kWh if electricity is produced using innovative processes such as fuel cells, gas turbines, organic Rankine cycles or multi-fuel facilities such as Kalina cycles or Stirling engines. This bonus is also granted if gas from the network is used and the thermal equivalent in landfill gas, sewage gas or mine gas is fed into the network elsewhere. The gas fed in must be processed until it is of equivalent quality to natural gas (Article 7(2) first sentence EEG). The bonus may only be claimed once, either for the use of innovative technology or for gas fed into the network. It is not possible to claim twice, even where both conditions have been met (Table 7-1).

Table 7-1: Key rules in the Renewable Energy Sources Act on payment for electricity from landfill gas, sewage gas and mine gas [6]

	Scheme of minimum fees for facilities commissioned in 2007 (basic values for facilities commissioned in 2004 in brackets)	Remuneration period	Degression for newly commissioned facilities
Basic fee	Capacity up to 500 kW_{el}: 7.33 cents/kWh (7.67 cents/kWh) Capacity from 500 kW_{el} to 5 MW_{el} 6.35 cents/kWh (6.65 cents/kWh) Capacity from 5 MW_{el} (mine gas only): 6.35 cents/kWh (6.65 cents/kWh)	20 years + year of commissioning	1.5% p.a. from 1.1.2005
Bonus provision	A bonus of 2 cents/kWh is payable either for gas of natural gas quality fed into the network or for employing innovative technology in the facility.		

7.1 Market development and electricity production costs

The market for landfill gas in Germany is largely saturated and will disappear in the medium to long term due to waste legislation, which since 1 June 2005 has prohibited the landfilling of untreated organic material. The majority of potential on the German sewage gas market has also been tapped. Any potential energy yet to be harnessed in these two markets therefore lies primarily in the renewal of existing facilities.

In contrast, the inclusion of mine gas in the scope of the EEG in 2000 brought about dynamic developments in the market, although this expansion slowed significantly for the first time in 2005. The remaining potential on this market lies mainly in harnessing old pits without any gas extraction infrastructure, from which mine gas would otherwise escape to the surface unchecked.

In the context of this technology bonus, two facilities in Germany have so far developed facilities based on the organic Rankine principle, and one uses sewage gas to generate electricity using a fuel cell.

Table 7-2 provides an overview of the volumes of electricity produced in landfill gas, sewage gas and mine gas facilities between 2003 and 2005, and the associated reduction in CO_2 emissions. However, no account has been taken of the contribution made to emission reduction by the conversion of methane to carbon dioxide. Methane is especially harmful to the climate, much more so than carbon dioxide (the global warming potential of methane is 21, while that of CO_2 is 1).

Table 7-2: Key features of developments in electricity generation from landfill gas, sewage gas and mine gas between 2003 and 2006, after [1, 2, 4]

	2003	2004	2005	2006
No. of facilities				770
Total installed capacity (MW_{el})				598
Electricity generated (GWh/a)	1,760	2,589	3,136	2,789
of which landfill gas	800	1,000	1,050	1,050
of which sewage gas	220	240	888	270
of which mine gas	740	1,100	1,198	1,469
EEG payments (million €/a)		180.46	214.36	195.62
EEG fee (in cents/kWh)		6.97	6.84	7.01
CO_2 emissions reduced (in million tonnes/a)	No data	2.667	3.230	3.303
of which landfill gas	0.824	1.030	No data	1.143
of which sewage gas	0.227	0.247	No data	0.966

A comparison of electricity production costs with EEG payments shows that, for landfill and sewage gas, small facilities with a capacity of under 300 kW_{el} may be economically viable to operate under favourable conditions. The larger the facility, the greater the span between the reduction in costs and the decrease in remuneration rate.

Landfill gas

Fig. 7-1 illustrates this phenomenon using the typical electricity production costs for landfill gas facilities commissioned in 2006. For the smaller facility used as an example (250 kW_{el}), the costs are 7.01 cents/kWh. Feed-in payments of 7.44 cents/kWh mean that it is economically viable to operate. For the larger, 2 MW_{el} facility, the costs of 4.01 cents/kWh are compared with potential profits of 6.76 cents/kWh. In principle, this means that an imputed interest rate significantly higher than the interest rate used for the reference case (8% p.a.) can be achieved [1].

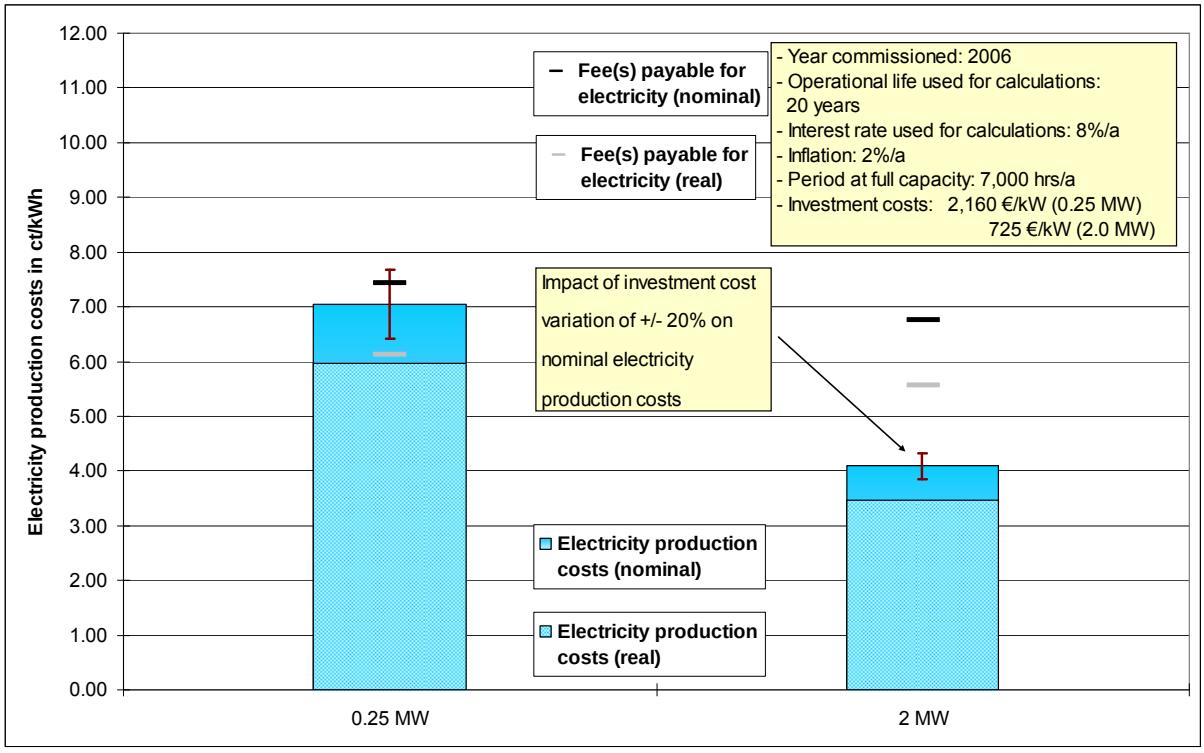


Fig. 7-1: Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for landfill gas facilities (basic case), ZSW et al. 2007[4] [1]

However, in practice investment risks exist, and these lead to higher electricity production costs. This is particularly true for landfill gas facilities (but also for mine gas facilities). The risk for landfill gas is primarily one of a decrease in the volume and quality of gas as the age of the landfill site increases. The scale of this decrease cannot be estimated in advance. It is therefore advisable to apply useful lives significantly shorter than 20 years in calculations. If we apply a useful life of six years, larger facilities can achieve economic viability, but small facilities cannot (Fig. 7-1). Although the significance of the cost effects due to gas volume and quality cannot be verified satisfactorily due to a lack of practical data, no notable freerider effects can be expected for landfill gas facilities in the future as this is a small, shrinking market.

[4] The costs are shown in real terms, i.e. adjusted for inflation, and as nominal figures without considering inflation. As the rates of payment under EEG represent nominal figures, these should be compared to the nominal electricity production costs. For completeness, inflation was also included on the income side (real payment). Real electricity production costs should therefore be compared with real payments and nominal electricity production costs with nominal payments. (See also Chapter 15.1 page 163 ff.)

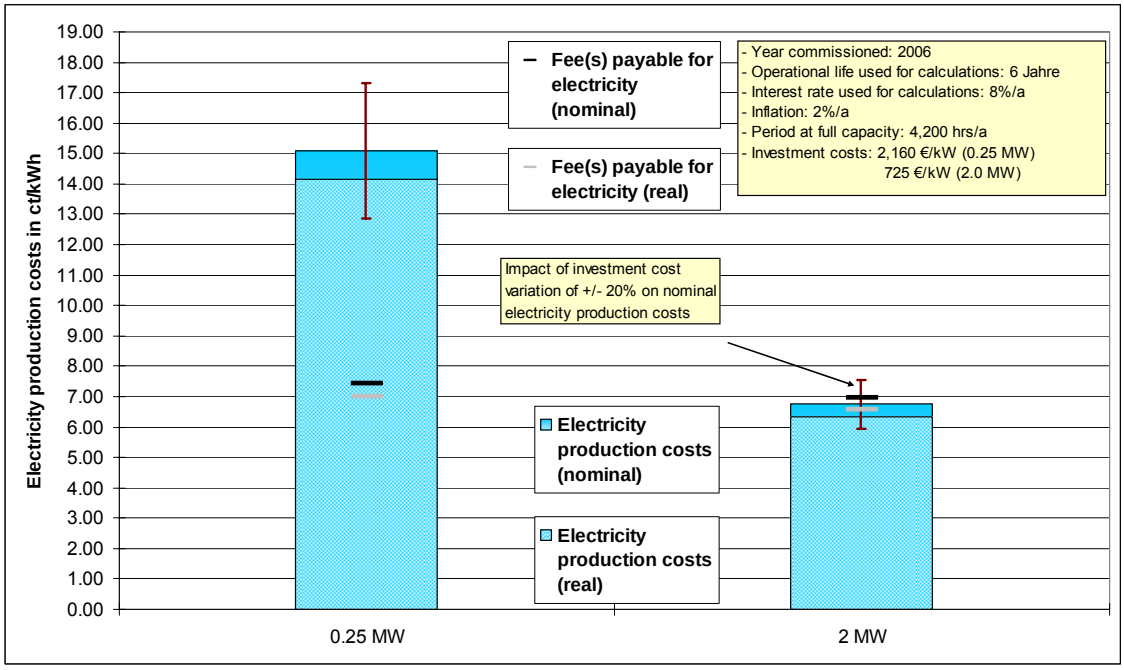


Fig. 7-2: **Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for landfill gas facilities (variant), after ZSW et al. 2007[5] [1]**

Sewage gas

Fig. 7-3 shows the electricity production costs for electricity from sewage gas at different composite interest rates, with and without heat extraction.

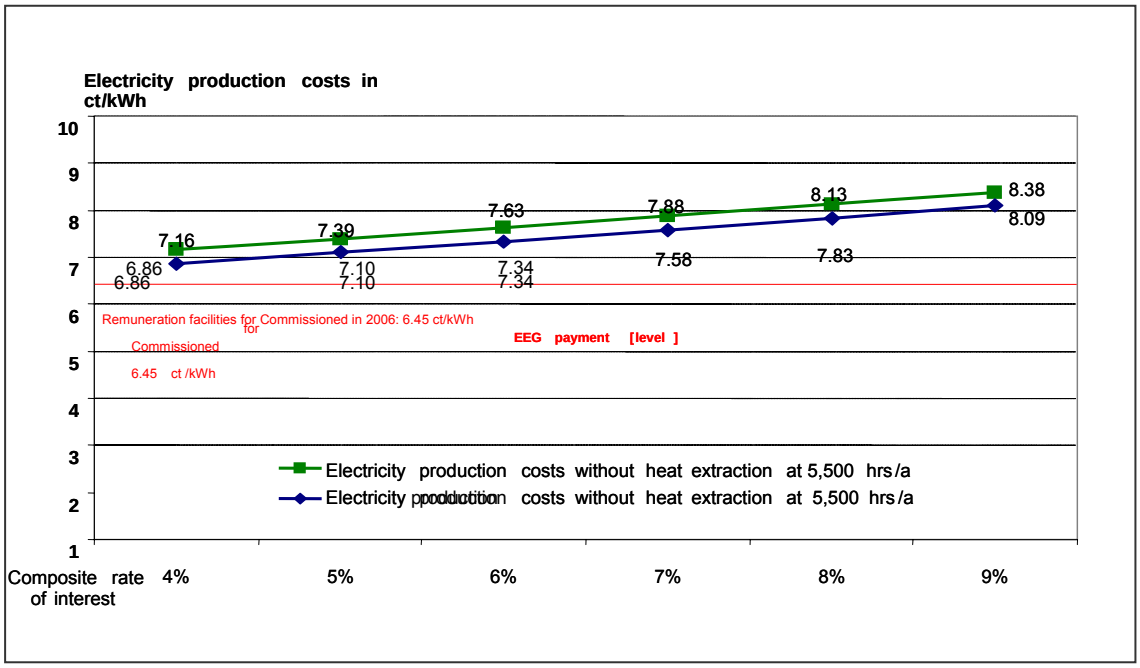
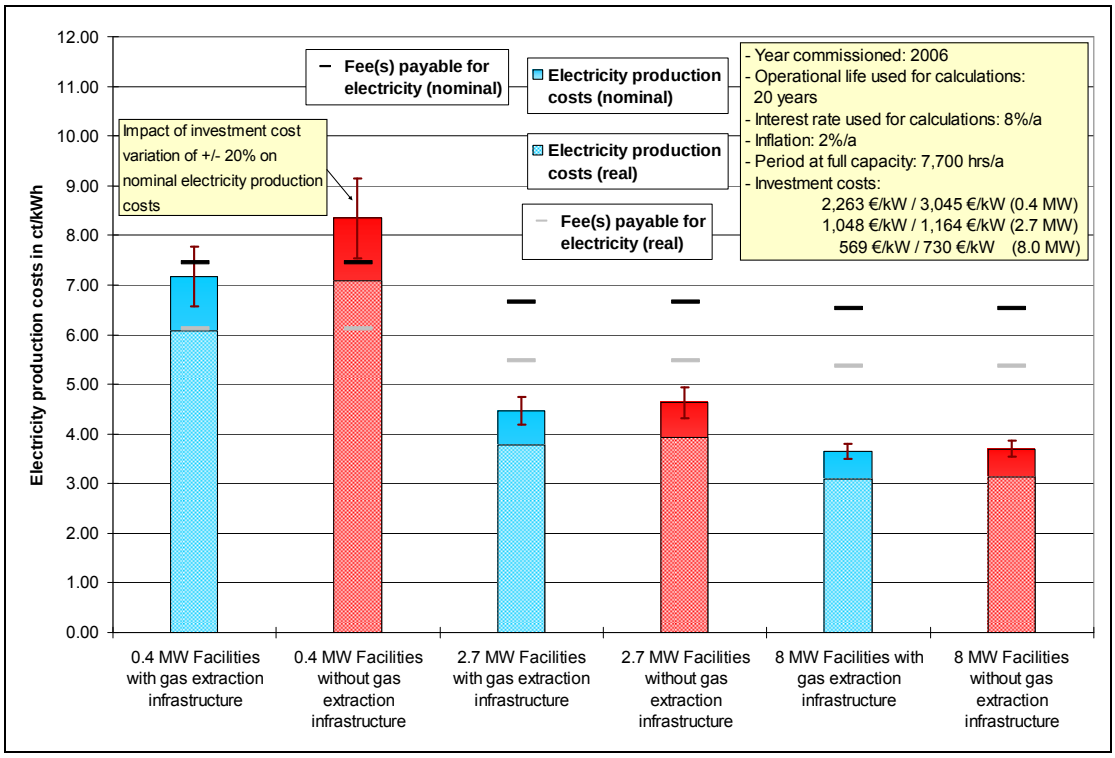


Fig. 7-3: **Electricity production costs for 0.5 MW_{el} sewage gas facilities depending on interest rates, in cents/kWh, after IE/Prognos 2006 [14]**

5 See footnote 4 to Fig. 7-1 on page 66 and Chapter 15.1 page 163 ff.

Mine gas

Exploration risks exist for mine gas, as we have no detailed knowledge of the structure of clefts, cavities and infills in the overlying rock. What is more, the volume of gas available may decrease over time if the groundwater table rises after the end of coal mining at a mine site. These risks may also be reflected in the number of hours a year for which the facility runs at full load. In good locations, with optimal management, a total of 7,700 hours at full load can be achieved. This figure has therefore been used as a basis for the calculations on economic viability below. Yet there are many examples of significantly lower facility utilisation. If these risks are represented by means of a higher interest rate (12% p.a. instead of the nominal 8%) or shorter useful life, smaller facilities cease to be economically viable. According to the data available, facilities with a capacity of over 1 MW_{el} remain economically viable, even in the above case. Fig. 7-4 illustrates the viability of typical facilities with capacities of 0.4 MW_{el}, 2.7 MW_{el} and 8 MW_{el}, commissioned in 2006. Due to the particular nature of mine gas projects, as outlined above, the electricity production costs for sites with and without gas extraction infrastructure are shown separately. At sites with gas extraction infrastructure, the production costs of 7.17 cents/kWh for an 0.4 MW_{el} facility approximately match the EEG fee payable, while costs for 2.7 MW_{el} and 8 MW_{el} facilities lie well below the respective EEG fees of 6.66 cents/kWh and 6.52 cents/kWh. Where no gas extraction infrastructure is available, electricity production costs rise significantly. It is no longer economically viable to operate the 0.4 MW facility with fees payable at the current level. Although higher, the costs for the two larger facilities remain below the level of EEG fees payable [1].



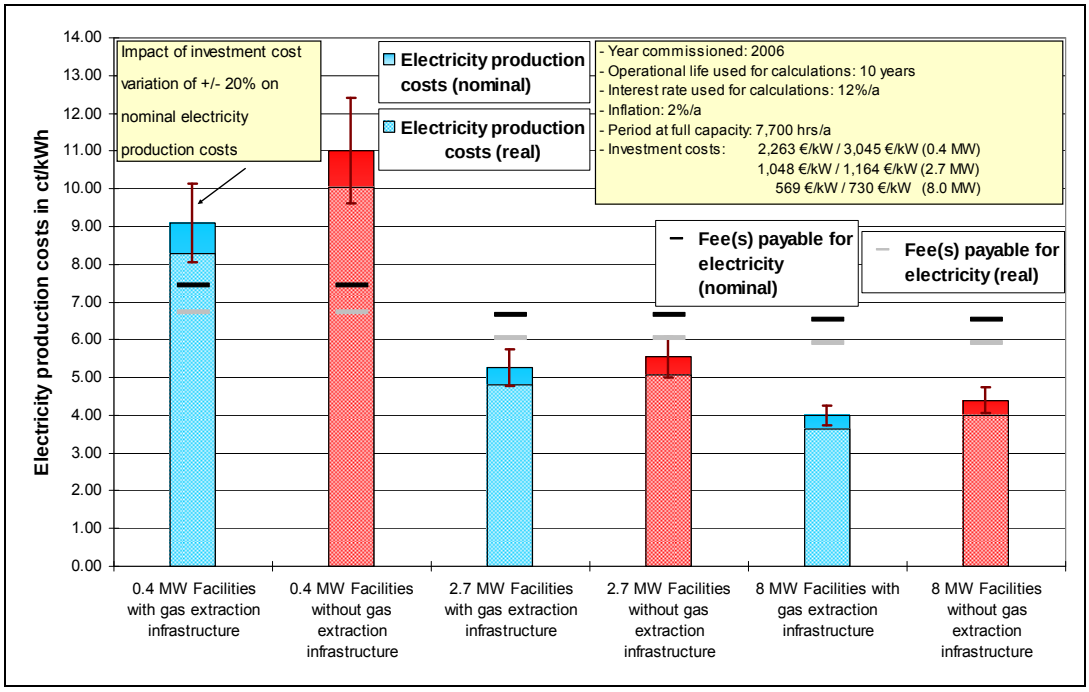
** EGISt = Entgasungsinfrastruktur = Gas extraction infrastructure*

Fig. 7-4: Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for mine gas facilities (basic case), after ZSW et al. 2007 [6] [1]

[6] See footnote 4 to Fig. 7-1 on page 66 and Chapter 15.1 page 163 ff.

As it had been for landfill gas facilities, a sensitivity analysis was conducted for mine gas facilities as regards useful life and return on equity. As both larger model facilities were economically viable even under these conditions (Fig. 7-5), there is clear scope for freerider effects.

Furthermore, an additional sensitivity analysis was conducted on various local conditions for mine gas facilities in North-Rhine/Westphalia and Saarland. The above calculations assumed good local conditions and optimal management, as per the analysis scheme detailed in Chapter 5.1, and therefore used the figure of 7,700 hours a year at full load. This figure was achieved in Saarland, but the facilities in North-Rhine/Westphalia only achieved an annual average of around 5,300 hours in recent years.



** EGISt = Entgasungsinfrastruktur = Gas extraction infrastructure*

Fig. 7-5: Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for mine gas facilities (variant 1), after ZSW et al. 2007 [7] [1]

The difference in numbers of hours at full load is due in part to the use of different technologies, particularly different gas extraction infrastructures. In Saarland, mine gas is collected via a network and thus transported to facilities for utilisation, whereas in North-Rhine/Westphalia such facilities are generally on site and not part of a network. Another factor is that large facilities/many assemblies were initially built in North-Rhine/Westphalia which later had to be dismantled due to site-specific exploration risks. However, experience gathered at new facilities indicates that it is possible to achieve a much higher number of hours at full load in North-Rhine/Westphalia.

[7] See footnote 4 to Fig. 7-1 on page 66 and Chapter 15.1 page 163 ff.

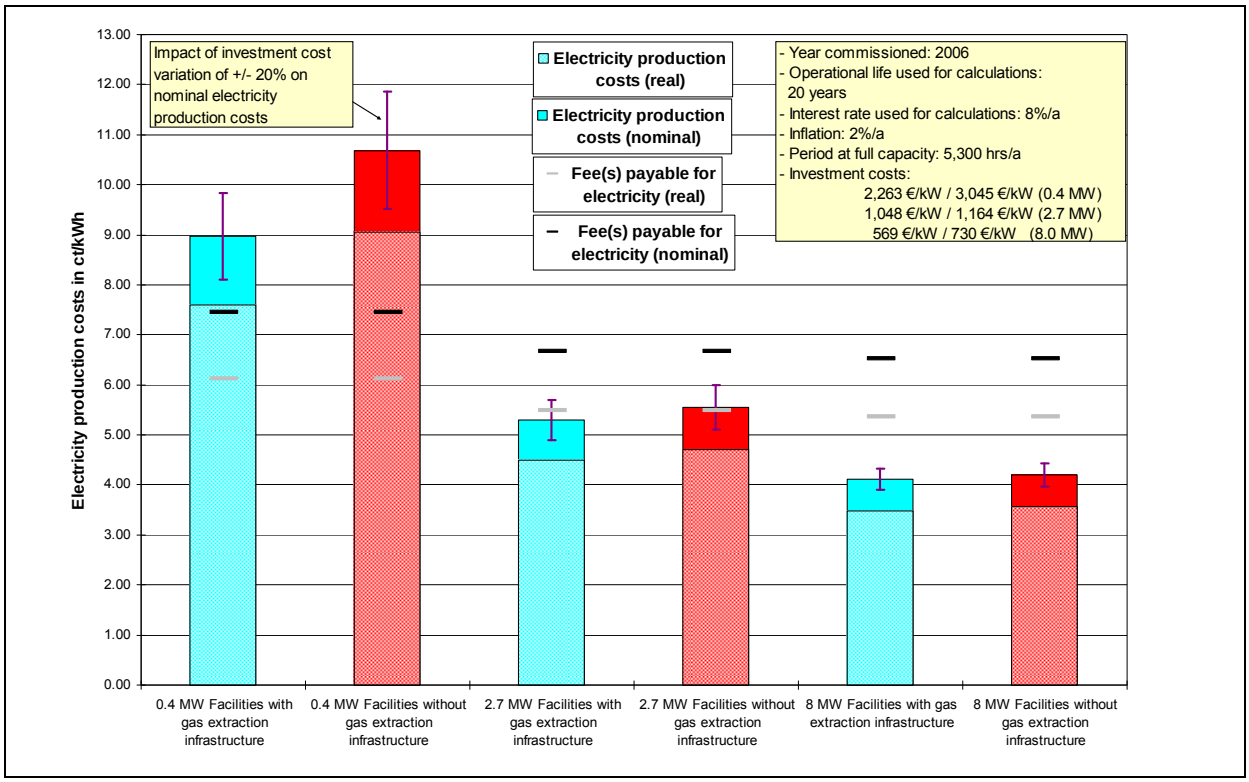


Fig. 7-6: **Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) for facilities with 5,300 hrs/a at full load as against the mid-rate of remuneration (real and nominal) for mine gas facilities (variant 2), after ZSW et al. 2007 [8] [1]**

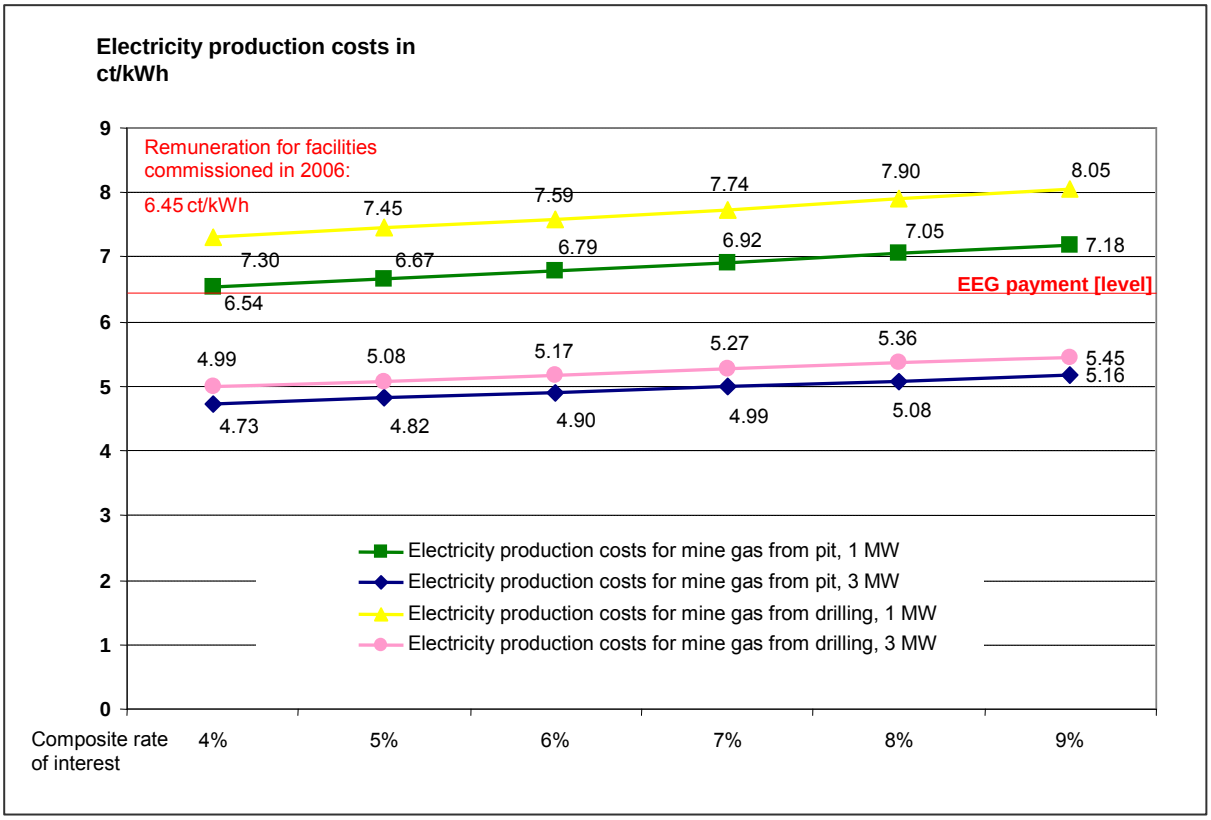


Fig. 7-7: **Electricity production costs for 2.5 MW mine gas facilities depending on the interest rate, in cents/kWh, after IE/Prognos 2006 [14]**

8 See footnote 4 to Fig. 7-1 on page 66 and Chapter 15.1 page 163 ff.

7.2 Environmental evaluation of provisions under the EEG

As facilities which utilise landfill gas, sewage gas and mine gas generally cover small areas of land which is already polluted, there are no large-scale effects on nature or the landscape. Indeed, the use of landfill and sewage gas for energy helps towards climate protection targets. This also applies to mine gas, where it would escape into the atmosphere if not used for energy. Very little energy use was made of mine gas in particular prior to 2004. Mine gas consists largely of methane, which is especially detrimental in terms of climate change, and was in many places escaping directly through gas extraction pipelines (cold flaring) or diffusing into the atmosphere through clefts and splits in the overlying rock.

The use of facilities to exploit the energy potential of mine gas and thus prevent the uncontrolled diffusion of methane emissions is therefore a positive step. The inclusion of mine gas utilisation in the EEG payment system was therefore justified, although it is not a renewable source of energy.

Apart from the existing mine gas projects, we are not aware of any sites where mine gas is escaping into the atmosphere of its own accord in relevant quantities. Any further mine gas projects funded under the EEG would therefore only be possible if the mine gas were actively extracted. Yet this would mean supporting and using fossil fuels, and as such is not in line with the objectives of the EEG. It would increase rather than decrease greenhouse gas emissions.

In order to prevent active drilling for mine gas once the potential for gas escaping unbidden has been exhausted, it would seem appropriate to restrict remuneration for electricity from mine gas to gas from active and disused pits.

7.3 Policy recommendations

We therefore recommend retaining the EEG's general provisions for electricity generation from landfill and sewage gas largely unchanged, making only adapting selected adaptations (see box).

The remaining potential for the exploitation of landfill and sewage gas is limited. A trend towards the construction of smaller facilities is expected, due in particular to the decline in availability of landfill gas. Given the EEG fees currently payable, such projects will no longer make economic sense. So that the remaining potential can be exploited, we would recommend raising the level of EEG fees payable to newly commissioned landfill gas facilities with a capacity up to and including 500 kW_{el} to 9.0 cents/kWh (for facilities commissioned in 2009). We would also advocate checking whether the fees payable to the sewage gas sector could be lowered. It would also make sense to consider a combination with other renewable energies, especially with the use of biogas for energy. This would in turn be a reason to lift the requirement for exclusive use in Article 8 EEG (biomass).

Meanwhile, new financing options are now available, even for mine gas projects, through the Kyoto mechanisms, and in particular the provisions of the Project Mechanisms Act (*Projekt-Mechanismen-Gesetz – ProMechG*) [20]. The type of mine gas project outlined above could therefore be financed this way, provided the provisions of the EEG and ProMechG prohibiting multiple sale did not preclude this. A policy recommendation is supplied in Chapter 5.5.

The current investigation into electricity production costs for well-managed facilities exploiting the energy potential of mine gas at suitable sites has shown that the fees payable to facilities of over 1 MW_{el} at present are higher than they need be for operation to be economically

viable. The fees should therefore be reduced by 1 cents/kWh for capacities between 1 MW_{el} and 5 MW_{el} and by 2 cents/kWh for capacities above 5 MW_{el}.

However, the fee currently payable for electricity from mine gas facilities with a capacity of between 500 kW_{el} and 1 MW_{el} does not normally allow even well-managed facilities at good locations to be economically viable. The capacity classes for mine gas facilities should therefore be changed from: under 500 kW_{el}, and 500 kW_{el} – 5 MW_{el} to: under 1 MW_{el}, and 1 MW_{el} – 5 MW_{el}. Specifically, the fee payable to the "500 kW_{el} – 1 MW_{el}" class should be increased by 1 cents/kWh to 7.16 cents/kWh for facilities commissioned in 2009.

In the past, the size of mine gas facilities sometimes changed after a relatively short period of operation. This gave figures for number of hours at full load which were lower than made business sense, and therefore meant higher costs. For this reason, provided the obligation to pay fees to such facilities is to remain, facility size should be fixed for the duration of that obligation.

Furthermore, research projects and investigations are currently underway into the possibility of supporting mine gas not from active or disused mines, i.e. coal bed methane. Exploration for such gas would constitute a clear, exclusive promotion of a fossil fuel. We would not expect any non-natural outgassing of mine gas, as can occur in active or disused mines. Supporting mine gas exploration for coal bed methane by means of an obligation to pay fees under the EEG would conflict with the objective of the Act as stated in Article 1 EEG. We therefore advocate restricting the obligation to pay fees for electricity from mine gas to active and disused mines.

Policy recommendations for the provisions on electricity generation from landfill, sewage and mine gas

Provisions within the scope of the EEG

- Consider whether the level of fees for sewage gas plants can be lowered
- Increase in level of fees for landfill gas plants (commissioned in 2009) with a capacity of up to 500 kW_{el} from 7.11 ct/kWh to 9.0 ct/kWh in order to harness the remaining potential here
- Capacity classes for mine gas plants changed to

  0 – 1 MW_{el} (currently 0 – 500 kW_{el}) and
  1 – 5 MW_{el} (currently 500 kW_{el} – 5 MW_{el})

  plus adaptation of fees as follows (for plants commissioned in 2009)

  Share of capacity up to 1 MW_{el} 7.16 ct/kWh (currently 7.16 ct/kWh or 6.16 ct/kWh)
- Reduction in fees payable for mine gas plants with a capacity of over 1 MW_{el} as follows (for plants commissioned in 2009)

  Share of capacity from 1 to 5 MW_{el}: 5.16 ct/kWh (currently 6.16 ct/kWh)
  Share of capacity over 5 MW_{el}: 4.16 ct/kWh (currently 6.16 ct/kWh)
- Obligation for the size of a mine gas plant to be fixed when it is commissioned
- Remuneration for electricity from mine gas limited to gas from active and disused pits, i.e. no support for electricity production from coal bed methane (CBM).

8 Electricity from Biomass (Article 8 EEG)

The provisions for generating electricity from biomass within the meaning of Article 8 EEG are comparatively complex, due in part to the variety of substances, possible applications and technical processes involved. The Biomass Ordinance under the EEG [22] stipulates which types of biomass and process may be approved within the meaning of Article 8(1) EEG, and which environmental criteria must be met.

In contrast to the other branches of renewable energy, biomass is currently subject to the principle of exclusive use in accordance with the first sentence of Article 8(1) EEG. Hybrid facilities, which utilise biomass alongside other materials or renewable energy sources, are not therefore eligible for EEG payments for electricity from biomass. Thus for example the co-incineration of wood and straw in coal-fired power stations and the burning of mixed municipal waste are ineligible. Even the desirable practice of hybridising biomass with solar thermal or geothermal facilities is ineligible. Furthermore, the obligation to pay fees is tied to the facility's maximum capacity. If this capacity exceeds 20 MW_{el} then the facility is not eligible for any payment.

A remuneration period of 20 years (plus the year of commissioning) applies to all facilities under the EEG. As with most branches of renewable energy, the actual remuneration payable depends on the year in which the facility was commissioned. The legal minimum payment in accordance with Article 8(1) EEG is subject to a progressive reduction of 1.5% per year. Three bonuses, which are not subject to this progressive reduction, were introduced in the 2004 revision of the EEG:

- The "NawaRo bonus" (NaWaRo is an abbreviation of "nachwachsende Rohstoffe", the German for cultivated biomass) for facilities which only utilise plants or parts of plants which have originated from agricultural, silvicultural or horticultural operations or during landscaping activities and which have not been treated or modified in any way other than for harvesting, conservation or use in the biomass facility, and/or manure within the meaning of Regulation (EC) No 1774/2002, or from vinasse generated at an agricultural distillery pursuant to Article 25 of the Spirits Monopoly Act, if that vinasse is not subject to any other recovery requirements pursuant to Article 25(2) No. 3 or Article 25(3) No. 3 of the Spirits Monopoly Act.

- The technology bonus, which is granted where the processes and technologies listed conclusively in Article 8(3) EEG are employed. The processes benefiting from this bonus include: thermochemical gasification or dry fermentation, where biogas used for power generation is processed to reach the quality of natural gas, electricity generated by means of fuel cells, gas turbines, steam engines, organic Rankine cycles and multi-fuel facilities (especially Kalina cycles) or Stirling engines.

- The CHP bonus, which is an incentive to operate facilities using combined heat and power generation.

The graduated levels of bonuses based on capacity and their cumulative nature make a significant difference between the levels of fees payable. At 8.03 cents/kWh, the basic fee payable to facilities with a capacity of 20 MW_{el} commissioned in 2007 forms the lower limit of this range. The upper limit of 20.99 cents/kWh applies to small, 150 kW_{el} facilities claiming all bonuses (see Table 8-1).

Table 8-1: Key rules in the Renewable Energy Sources Act on payment for electricity from biomass [6]

	Scheme of minimum fees for facilities commissioned in 2007 (basic figures for facilities commissioned in 2004 in brackets)	Remuneration period	Degression for newly commissioned facilities
Basic fee for facilities up to 20 MW_{el}	Capacity up to 150 kW_{el}: 10.99 cents/kWh (11.50 cents/kWh) Capacity from 150 kW_{el} to 500 kW_{el}: 9.46 cents/kWh (9.90 cents/kWh) Capacity from 500 kW_{el} to 5 MW_{el}: 8.51 cents/kWh (8.90 cents/kWh) Capacity from 5 kW_{el} to 20 MW_{el}: 8.03 cents/kWh (8.40 cents/kWh)	20 years + year of commissioning	1.5% p.a. from 1.1.2005
Bonus provisions	NaWaRo bonus: Capacity up to 500 kW_{el}: 6 cents/kWh Capacity from 500 kW_{el} to 5 MW_{el}: 4 cents/kWh, (where wood burnt, 2.5 cents/kWh) Technology bonus: 2 cents/kWh CHP bonus: 2 cents/kWh		
Particular requirements	• Scope only covers facilities up to 20 MW_{el} • Principle of exclusive use, i.e. hybrid facilities not eligible for payment. • The different bonuses may be claimed cumulatively; the technology bonus is only granted once. • The technology bonus is granted up to a capacity of 5 MW_{el}. • The CHP bonus is only granted for the volume of electricity produced using combined heat and power generation. • Facilities using waste wood classified in categories A III and A IV: for facilities commissioned prior to 30.6.2006, fees as for other facilities; for facilities commissioned after 30.6.2006, additional reduction in fees, regardless of capacity, to 3.78 cents/kWh; for facilities commissioned from 2007, degression of 1.5% p.a. – bonus provisions do not apply.		

8.1 Market development and electricity production costs

The total installed electrical capacity of bioenergy facilities in Germany within the meaning of Article 8 EEG increased considerably between 2000 and 2006 (see Table 8-2). However, the trends for energy production from solid, liquid and gas biomass showed marked differences; it would therefore be appropriate to consider each one separately.

The development of electricity generation from solid biomass has been fairly continuous since 2000. From 200 MW_{el} in 2000, the installed electrical capacity rose to 1,100 MW_{el} by 2006. Over a third of all such facilities lie in the 5 to 20 MW_{el} capacity range. This is due to the predominant steam turbine designs and the significant economies of scale associated with them. These facilities produce the majority of the electricity generated from solid biomass. Whereas the large facilities use mainly waste wood, the smaller facilities under 5 MW_{el} use mainly forestry and industrial residue, some of which is produced by the operators themselves. It is estimated that around 65-75% of the fuel employed is waste

wood, 20-25% industrial residue and sawmill by-products and around 10% forestry residue and wood from landscape management.

Although the raising of the upper capacity limit in the 2000 EEG to 20 MW_{el} caused a particular boom in construction of facilities of over 5 MW_{el} between 2001 and 2004, the incentive provided by the NaWaRo, technology and CHP bonuses since the 2004 revision of the EEG has meant an increased trend towards small and medium sized biomass facilities of up to 5 kW_{el}. Although just 36% of the biomass facilities operating in 2004 had a capacity of up to 2 MW_{el}, this rose to 77% by the end of 2006. Of the solid biomass used for electricity production, around 6% was cultivated biomass within the meaning of Article 8(2) EEG in 2004, rising to around 9% in 2006.

Table 8-2: Key features of developments in electricity generation from biomass between 2003 and 2006, afer [1, 2, 3, 4, 23]

	2003	2004	2005	2006
No. of facilities			3,490	5,262
Total installed capacity (MW_{el})	678	1,091	1,733	2,331
Annual new installations (MW_{el}/a)	185	413	642	598
Electricity generated from biomass (GWh/a)[1)]	3,483.6	5,241.0	7,366.5	12,000
EEG payments (million €/a)	326.68	503.68	777.47	1,337
EEG fee (in cents/kWh)	9.38	9.61	10.55	12.27
CO_2 emissions reduced (in million tonnes/a)	2.8	4.2	5.9	9.8
Jobs[1)]	No data	23,800	No data	64,000
of which in biogas	No data	4,300	No data	10,600
of which in solid biomass	No data	19,200	No data	52,600
of which in liquid biomass	No data	300	No data	800

1) The VDN calculated the volume of electricity from biomass receiving EEG payments as 10,901.6 GWh in 2006. The figure shown originates from an estimate by the working group on renewable energy statistics, dated 10/2007. This includes energy generation not eligible for EEG payments for biomass, but not biogenic waste.

2) Activity outside the scope of the EEG also considered, but not activity in the biofuels sector

The introduction of the NaWaRo bonus in the 2004 EEG revision was a decisive factor for the growth in biogas facilities between 2004 and 2006, when the amount of capacity almost quadrupled. The annual increase in capacity had remained steady at between 30 and 60 MW_{el} in previous years, but leapt to 420 MW_{el} between 2004 and 2005. There was a stronger trend towards larger facilities. The NaWaRo bonus is currently claimed by about 60% of all biogas facilities. These comprise both new facilities and existing facilities converted to use cultivated biomass. Switching biogas facilities to the exclusive use of cultivated biomass has meant a decrease in the utilisation of industrial and agricultural residues in agricultural biogas facilities. However, we can assume that most of these residues, which can be fermented, continue to be utilised in fermentation facilities, and indeed that they occupy capacity in existing waste fermentation facilities. The fact that new waste fermentation facilities have been built also contradicts the view which is sometimes expressed that the introduction of the NaWaRo bonus has brought indifference towards the fermentation of residual and waste products.

The trend towards larger biogas facilities has continued. At the end of 2006, the average capacity for an existing biogas facility in Germany was 290 kW_{el}. Capacity varies greatly from region to region. While the average capacity in Brandenburg, Thuringia, Saxony-Anhalt, Lower Saxony and Mecklenburg-Western Pomerania is around 500 kW_{el}, in Baden-Württemberg it is 200 kW_{el} and in Bavaria 190 kW_{el}. The variation in facility capacity means

that Lower Saxony leads the *Länder*, with 27.4% of the installed biogas capacity, although the highest number of operational biogas facilities is still in Bavaria (41%).

In the sector comprising small-scale cogeneration units which run on vegetable oil, installed capacity increased rapidly between 2004 and 2006. Whereas in August 2004 installed capacity still lay at around 12 MW_{el}, by the end of 2006 it had risen to 237 MW_{el}, with the number of facilities growing more than tenfold over the same period, from 160 to 1800. More than three quarters of installed electrical capacity was made up of facilities of over 100 kW_{el}. Two main types of vegetable oil are used. The smaller units of up to around 100 kW_{el} generally run on rapeseed oil, while larger facilities of over 100 kW_{el} are generally fuelled with palm oil. It is calculated that around 400,000 tonnes of vegetable oil per annum are required to run the capacity installed at the end of 2006 (see Table 8-3), of which around 60,000 tonnes will be rapeseed and 340,000 tonnes palm oil. Major cost benefits in procurement lie behind the preference for palm oil as a fuel in small-scale cogeneration units which run on vegetable oil. At times, the price difference between the two types of oil has exceeded 200 euros a tonne. The significant increases in rapeseed prices have meant that even facilities which had largely run on rapeseed oil have now converted to palm oil.

Legal uncertainty has arisen in assessing claims to payment, particularly where palm oil has been used, and particularly where claims were for the higher minimum fee under Article 8(2) EEG. At the root of this uncertainty lie the production conditions for palm oil. In South-East Asia in particular, tropical forests are destroyed to free up some of the land for planting with oil palms. This sometimes involves illegal logging. The use of non-sustainably grown palm oil to generate electricity is not consistent with the objectives laid down in Article 1 EEG. Unfortunately, the origin of the palm oil used in EEG facilities cannot normally be reliably established. At present, it is debatable whether any such unsustainable palm oil is actually eligible for the NaWaRo bonus. As yet, there is no generally acknowledged certification system with which facility operators can establish that the palm oil they use in their EEG facilities has been produced sustainably. Facility operators are therefore generally unable to prove to grid system operators that they have fulfilled the practical conditions for claiming the higher minimum fee under Article 8(2) EEG. It is understandable, in these circumstances, that some grid system operators have granted the payment under Article 8(2) EEG subject to reservations. In a press release dated 16 January 2007, the Federal Environment Ministry referred to the financial risks for facility operators resulting from the use of palm oil to produce electricity.

Table 8-3: The structure of electricity generation from biomass in 2006 after [1, 23]

	Solid biomass	Biogas	Vegetable oil	Total
Number of facilities	160	3,300	1,800	5,260
Total installed electrical capacity in MW	1,090	1,000	240	2,330
Electricity generated (GWh/a)[1)]	6,520	4,170	1,310	12,000[2)]
Electricity generated (GWh/a)[1)]	1,900 – 3,700	310 – 360	260 – 310	2,470 – 4,370
Fuel and substrate used (in million tonnes/a)[1)]	4.0 – 4.7 (a. dry[3)])	23 – 27	0.23 – 0.26	

1) Simplified approach to time of commissioning for new facilities during the year

2) The VDN calculated the volume of electricity receiving EEG payments as 10,901.6 GWh in 2006.

3) a. dry = absolutely dry (0% water content)

While the influence of the NaWaRo bonus has been comparatively well documented, only limited conclusions can be drawn about the incentive provided for increased CHP operation as the relevant data are hard to come by. Once again, it makes sense to look at each bio-energy source in turn.

Heat and power facilities of up to 10 MW using solid biomass are mainly used for the cogeneration of heat and power, some primarily determined by the demand for heat, and some the demand for power. However, experience shows that facilities of over 1 MW_{el} often only use a small proportion of their capacity for heat. Around 40% of all facilities of over 10 MW_{el} are used exclusively to generate electricity, i.e. the proportion of facilities of this size used for combined heat and power generation is significantly smaller than the proportion of smaller facilities used for this. As a rough estimate, by the end of 2006 existing heat and power stations running on solid biomass (920 MW_{el}) had produced between 1,900 and 3,700 GWh_{th} of heat. This is equivalent to between 3 and 5% of the total heat generated by means of cogeneration in local and district heating systems in Germany.

The only means of estimating the status of cogeneration at biogas facilities was an operator survey. According to the survey, 43% of facility operators stated that they had implemented or planned to implement cogeneration following the introduction of the CHP bonus with the 2004 revision of the EEG. In total, 58% of those surveyed used the extracted heat generated externally in 2006. The extent to which the heat generated was utilised varied widely, ranging between 5 and 100%. Overall, around half of the heat generated was used. This development is proof of the influence exercised by the CHP bonus introduced in 2004. One factor in particular was cited as limiting the further expansion of heat use: the restriction of the CHP bonus to facilities commissioned from 1 January 2004 onwards. A further limiting factor was the difficulty in many cases of finding sites for biogas facilities close to reasonably large heat loads.

Small-scale cogeneration units run on vegetable oil do generally use the heat produced when generating electricity. Facilities in the smallest capacity ranges (up to 50 kW) are largely run for the purpose of generating heat, and to supply hot water. Large facilities are often used to supply heat to local authority and commercial buildings (such as schools, swimming pools, greenhouses and offices) and to provide industrial process heat.

On the whole, a clear trend towards increased heat use can be identified. There are a variety of reasons for the increased interest displayed by the operators and planners of facilities in utilising the heat produced during electricity generation. In addition to the incentive provided

by the CHP bonus, notable reasons include the rise in oil and gas prices and the associated increase in profits from the sale of heat. The rise in biomass prices has also meant that income from the CHP bonus and the sale of heat have become increasingly indispensable if EEG facilities are to achieve economic viability. Untapped heat potential can be found in particular in facilities commissioned prior to 31 December 2003, which are inelegible for the CHP bonus, and in the larger biomass facilities.

More precise information is available on the use of new technologies. In this case, the impact of the technology bonus introduced in 2004 is clearly identifiable. In particular, the introduction to the market of facilities using organic Rankine cycles (ORC facilities) with capacities of between 0.3 and 2.0 MW_{el} has benefited from the support of the technology bonus. By the end of 2006, 35% of biomass heat facilities under construction already had ORC technology. Of a total of 140 facilities utilising solid bio-energy sources, approximately 18 steam engines were in use by the end of 2005, all with a capacity of under 2 MW_{el}.

Interest in thermochemical gasification has also risen significantly as a result of the technology bonus. Preparations have been made for the introduction of various types of carburettor onto the market; the first such facilities are in operation, and look promising. However, long-term results are still required.

In terms of using gas as an energy source, interest in new technologies has focused on dry fermentation and on feeding processed biogas into the natural gas network. The first biogas facility to feed processed biogas into the natural gas network started operating in late 2006. Further projects have followed or are at the preparation stage. In some gas network areas, biogas must be conditioned with liquid petroleum gas (LPG) before it can be fed in. In such cases, the question arises of how to assess this mixing with the fossil fuel LPG in the light of the principle of exclusive use laid down in Article 8(1) first sentence EEG. We recommend the government consider including a clarification in the Act.

The technology bonus for dry fermentation has generated increased interest in the manure-free fermentation of cultivated biomass, particularly in regions with low or declining levels of livestock farming. It can be assumed that such processes will be mastered and successfully introduced onto the market. It has emerged that the features of the dry fermentation process cited in the explanatory memorandum to the EEG were not sufficient to describe these innovative dry fermentation processes in detail. This has resulted in significant legal uncertainty among facility and network operators about the scope of Article 8(3) EEG. Some interpret the act as meaning that all manure-free fermentation processes which employ silage from cultivated biomass and other solid substrates count as dry fermentation processes.

The electricity production costs are as varied as the means of generating energy from biomass. As a rule, it can be assumed that the level of EEG fees is reasonable given favourable conditions such as location, fuel/substrate cost, profits from the sale of heat etc. However, the smallest facilities – those with a capacity of up to 1 MW_{el} using solid biomass and up to around 0.1 MW_{el} using biogas and vegetable oil – are often unable to cover their operating costs.

Reference figures for production costs for electricity generation from solid biomass for typical facilities are shown in Table 8-4. As shown, the EEG remuneration that may be obtained tends to be sufficient only for larger facilities. For new facilities commissioned after 30 June 2006, the use of A III and A IV waste wood is not economically viable as the fees payable have fallen significantly, and now lie below the current market price for base load electricity.

However, the use of some waste heat is a key factor in economic viability, due to the fee payable for heat. Yet with steam engines and organic Rankine facilities, depending on the temperature, heat extraction can lead to lower degrees of electrical efficiency and thus

compromise energy generation. Nevertheless, the CHP bonus for electricity feed-in makes it possible to lower the price for heat by between 0.3 and 0.5 €/kWh. Thus the CHP bonus helps finance heat extraction.

Table 8-4: Economic conditions and cost assumptions for facilities generating electricity from solid biogenic fuels (facilities commissioned in 2006) [1]

	Model 1] 0.5 MW_{el}	Model 2] 2 MW_{el}	Model 3] 8 MW_{el}	Model 4] 20 MW_{el}
Type of facility	CHP, mainly for heat (5,000 hrs/a)	CHP, mainly for heat (5,000 hrs/a)	CHP, mainly for electricity (7,700 hrs/a)	Purely for electricity (7,700 hrs/a)
Technology	ORC facility	Steam powered	Steam powered	Steam powered
Fuel type	Forest residue mix, A I waste wood	Forest residue mix, A I, AII waste wood	Mainly A I, AII waste wood	A I – A IV Waste wood
Fuel costs	€60/tonne (a. dry[1)])	€53/tonne (a. dry[1)])	€30/tonne (a. dry[1)])	€16/tonne (a. dry[1)])

1) a. dry = absolutely dry (0% water content)

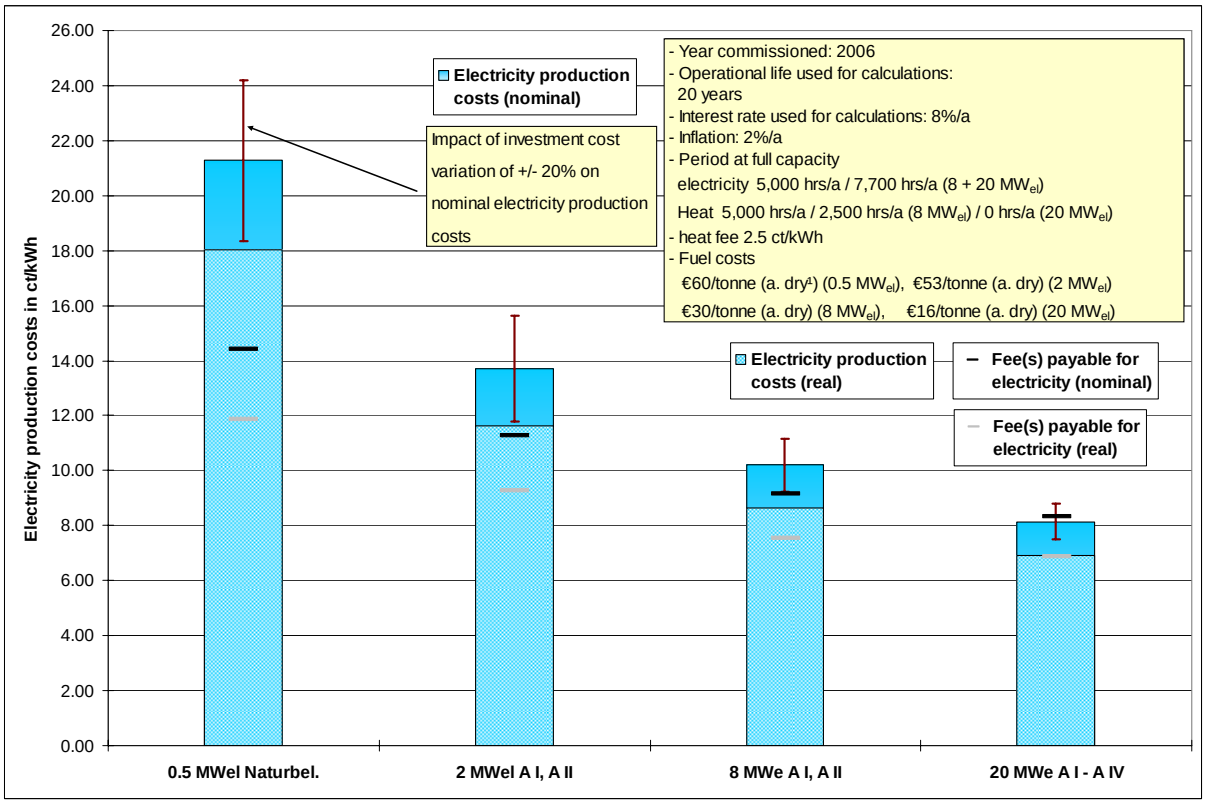


Fig. 8-1: Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for biomass (CHP) facilities in the basic case, after ZSW et al. 2007 [9] [1]

[9] The costs are shown in real terms, i.e. adjusted for inflation, and as nominal figures without considering inflation. As the rates of remuneration under the EEG are nominal figures, these should be compared to the nominal electricity production costs. For completeness, inflation was also included on the income side (real payment). Real electricity production costs should therefore be compared with real payments and nominal electricity production costs with nominal payments. (See also Chapter 15.1 page 163 ff.)

The CHP bonus has a much greater impact on the use of other technologies, where engines can use low temperature heat without having to accept lower standards of electrical efficiency. This permits the applicable heat price to be reduced by over 1 cent/kWh.

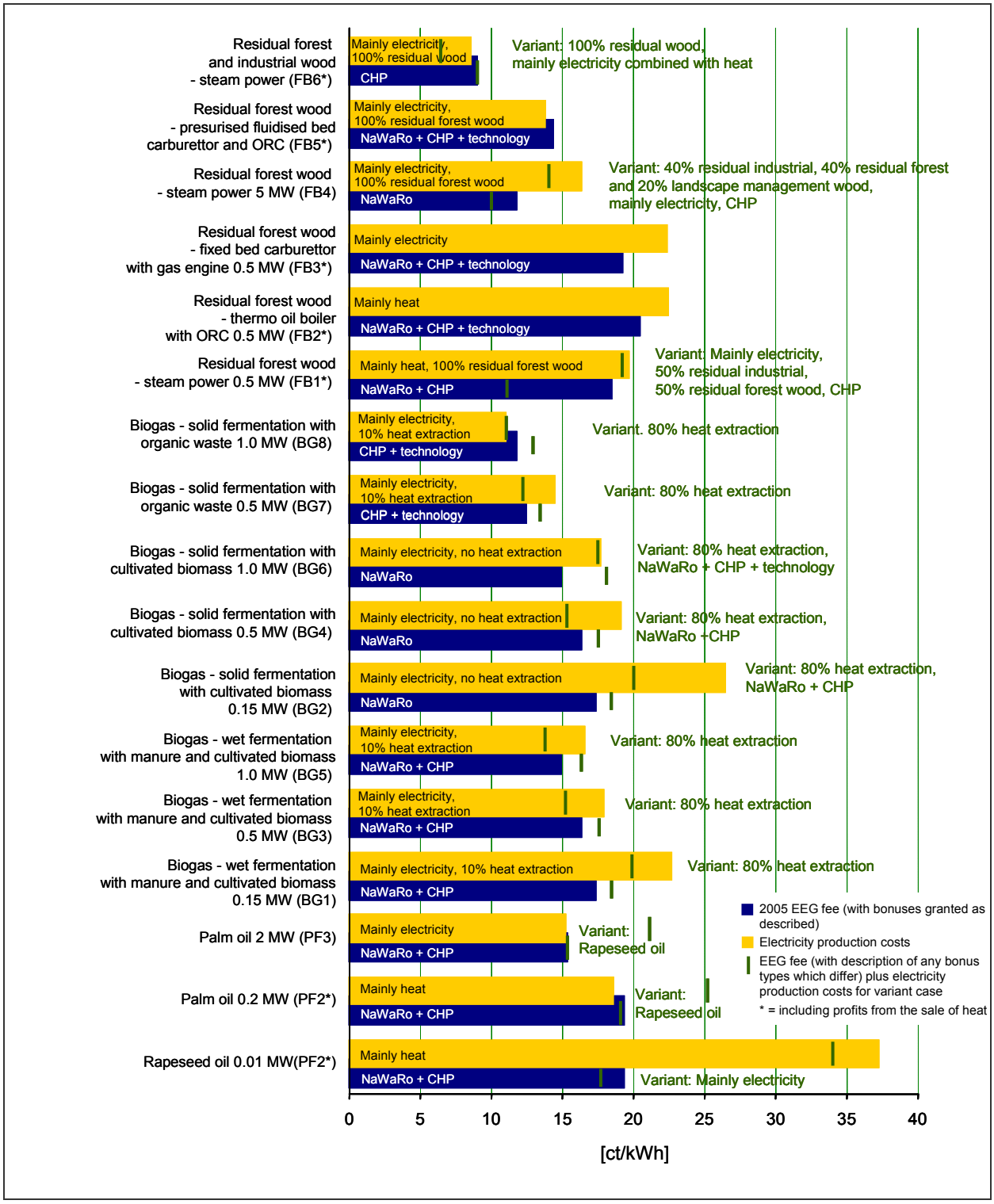


Fig. 8-2: Comparative table showing electricity production costs for facilities using biomass, with EEG feed-in fee, after IE/Prognos 2006 [14]

Introduction to electricity production costs for biogas facilities

The results for the economic viability of biogas facilities are based on calculations performed in 2006. As a basis for the calculations, we used completed operator surveys, and therefore initially assumed a basic cost of €25/tonne for agricultural substrate (such as maize silage) and an increase in substrate costs in line with inflation over the operational life of the facility. In 2007, the wholesale and producer prices for grain rose sharply, which also caused the free market price for silage to rise. However, any quantitative predictions as to the latest developments in the price of substrate and its effect on the economic viability of biogas facilities will be ridden with uncertainty. A very rough estimate of the effect of the rise in grain price since 2004 on a biogas facility which uses only energy crops from basic cultivation is shown below. Fig. 8-4 shows how electricity production costs depend on substrate costs.

Rough estimate of the impact of the rise in grain prices since 2004:

The price of agricultural raw materials is linked to the price of grain. The monthly index for May 2007 shows that the price of bread wheat had risen by 29% compared with the 2004 average. According to [3], the free market price of silage will rise by 17% if the cereal price rises by 30%. If we assume that this price rise is passed on in full to the operators of biogas facilities, they will experience a rise in substrate costs of around 17%.

In addition to substrate costs, and depending on the size of the facility, the specific investment costs and level of electrical efficiency also have a significant impact on the electricity production costs for a biomass facility. Substrate costs make up between 34 and 48% of overall annual electricity production costs. Assuming the maximum proportion of substrate costs, say 50%, electricity production costs rise by around 8.5% subject to the circumstances and assumptions as discussed.

Thanks to the NaWaRo bonus, facilities using solid biogenic fuels of up to several MW_{el} in capacity are able to cover their electricity production costs adequately where very reasonably priced forest residue wood can be procured. According to the assumptions applied in the model calculation, there is insufficient incentive for larger facilities of the same type. Equally, some facilities in the 20 MW_{el} class that use cultivated biomass within the meaning of Article 8(2) EEG have been built, despite the fact that the NaWaRo bonus is only granted to facilities of up to 5 MW_{el}. These projects have clearly achieved much lower electricity production costs than in the model calculation.

For all biogas facilities and small-scale cogeneration units which run on vegetable oil, the NawaRo bonus effects a significant increase in profits from electricity. Where this bonus is combined with the use of reasonably priced substrates/vegetable oils, facility operation is economically viable.

A basic variant of the results of the typical electricity production cost calculation for biogas facilities commissioned in 2006 is contrasted with the EEG fees payable in Fig. 8-3. Despite the bonus provisions already considered, with the exception of the large 1 MW_{el} capacity facility (we have discussed the feeding of prepared biogas into the natural gas network and CHP generation elsewhere), it is not economically viable to operate such facilities.

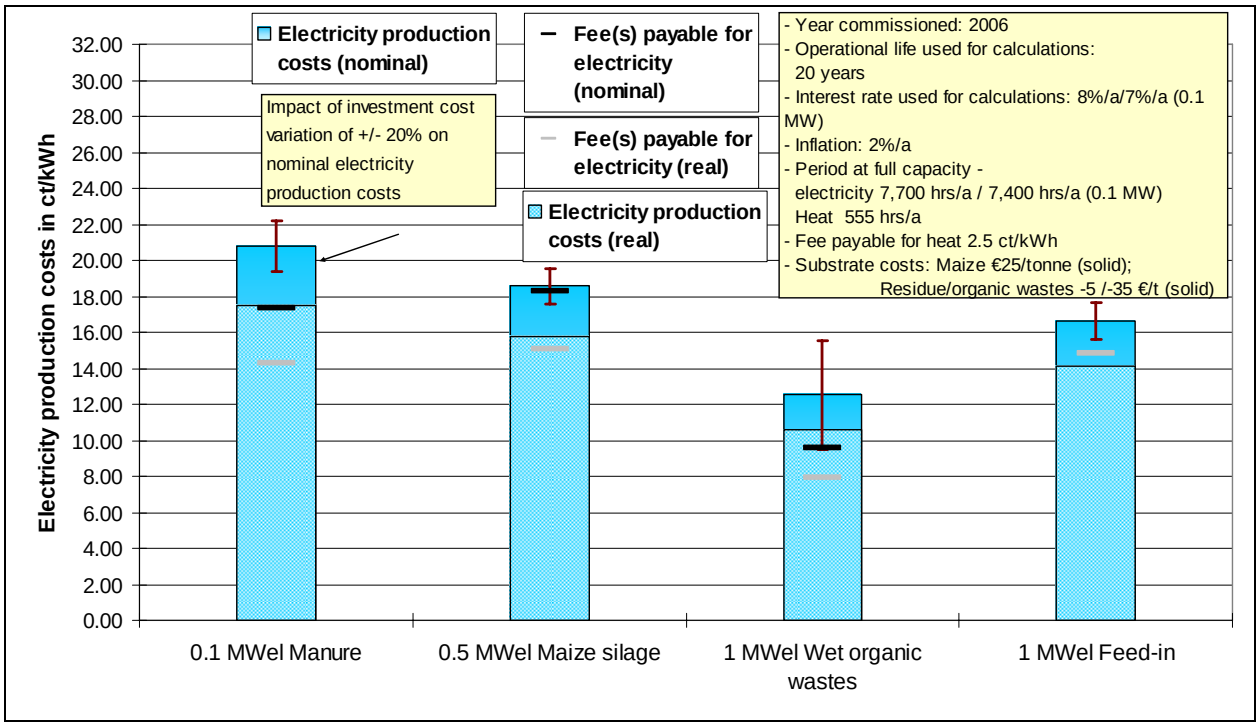


Fig. 8-3: Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal; where maize silage used, includes technology bonus) for biogas facilities in the basic case, after ZSW et al. 2007[10] [1]

However, the particular economic viability of facilities depends greatly on the size of the facility and by the substrates employed. Fig. 8-4 shows these distinctions for three different facility sizes (capacities 0.1 MW_{el}, 0.5 MW_{el} and 1 MW_{el}) and two different substrates (100% maize silage and 90% manure with 10% maize silage). It shows, among other things, that the electricity production costs for biogas facilities decrease as the capacity of the facility increases, given the same type of substrate. This is largely a result of the fall in specific investment and rise in efficiency which accompany an increase in facility capacity. The graph also shows that facility operation is only economically viable where a mixture of substrates is used, with a high proportion of manure. This fact means the capacity of the facility is limited, and/or some possible sites excluded, since a 1 MW_{el} facility would require manure from around 2,400 head of cattle/horses to achieve a 90% manure mixture.

Although manure is generally available at a reasonable price, since it is a by-product of livestock farming, the relevant provisions in the EEG make the use of cultivated biomass as a substrate appear more economically beneficial because energy crops are much more efficient in terms of gas output. Nor is manure available in the immediate vicinity of all facility sites. This has meant a current maximum of 10% of the manure occurring in Germany being used as a substrate in biogas facilities. The technology bonus payable for dry fermentation is also tending to entice operators away from manure. Yet the positive environmental impact of fermenting manure has been established, and as such this method should receive more support. This is the only way to exploit the potential which could make biogas facilities, especially smaller ones, economically viable.

[10] See footnote 9 to Fig. 8-1 on page 82 and Chapter 15.1 page 163 ff.

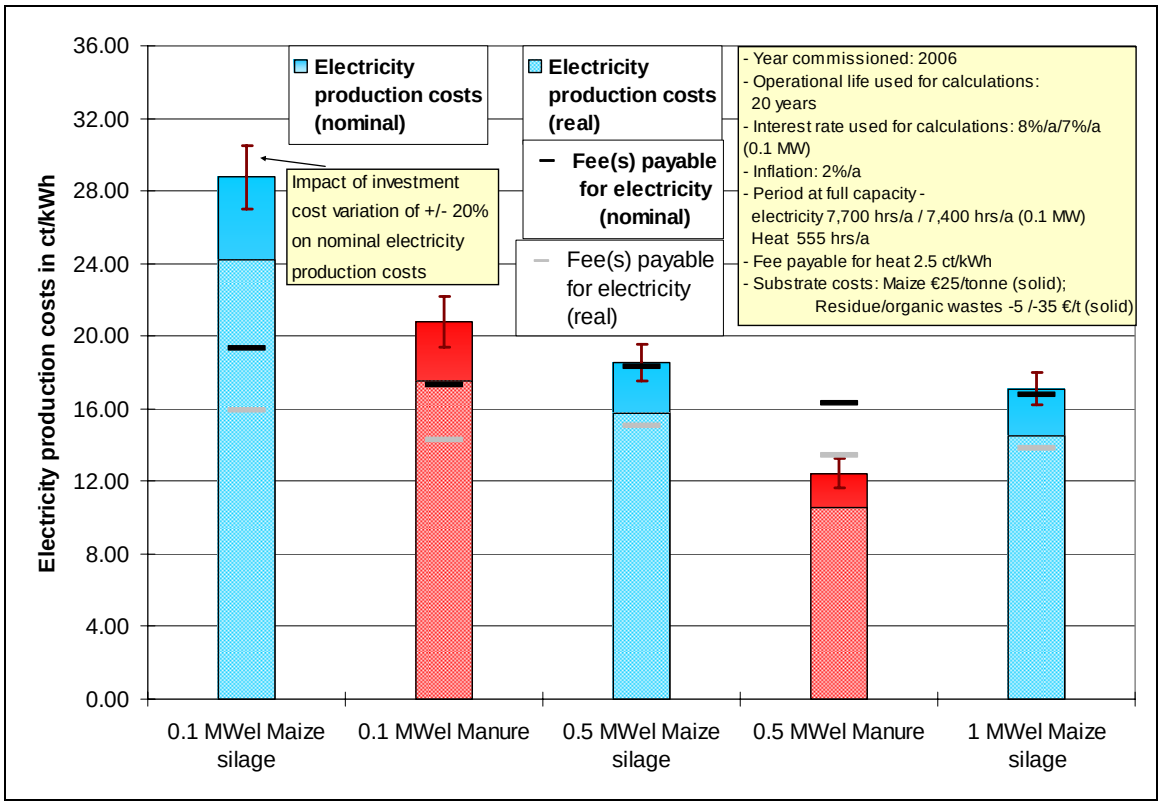


Fig. 8-4: **Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal; where 100% maize silage used, includes technology bonus) for biogas facilities using 100% maize silage and 90% manure, 10% maize silage (impact of NaWaRo bonus), after ZSW et al. 2007[11] [1]**

While figures 8-1, 8-2, 8-3 and 8-5 assumed fixed substrate costs, Figure 8-4 shows the link between electricity production costs and substrate costs for biogas facilities with an electrical capacity of 0.5 MW, using different substrates. The other parameters are identical to those in Figure 8-3. It should be noted that, as described above, the price of maize silage for example will rise by about 17% if the cereal price rises by 30%. This was the case between 2004 and May 2007. This link holds for all substrates, unless facility operators and substrate suppliers make other agreements.

The electricity production costs for facilities generating electricity from liquid biomass (currently only vegetable oil) also vary widely, depending on the size of the facility and the type of vegetable oil used (see Fig. 8-4). As vegetable oil costs constitute around 60 to 80% of electricity production costs, under current conditions economic viability is practically only achievable where facilities employ imported palm oil. In recent years, this has been significantly cheaper than domestic vegetable oil, e.g. rapeseed-based oil. However, the price of palm oil has followed an upward trend since mid-2006, and is now close to the price of rapeseed oil.

[11] See footnote 9 to Fig. 8-1 on page 82 and Chapter 15.1 page 163 ff.

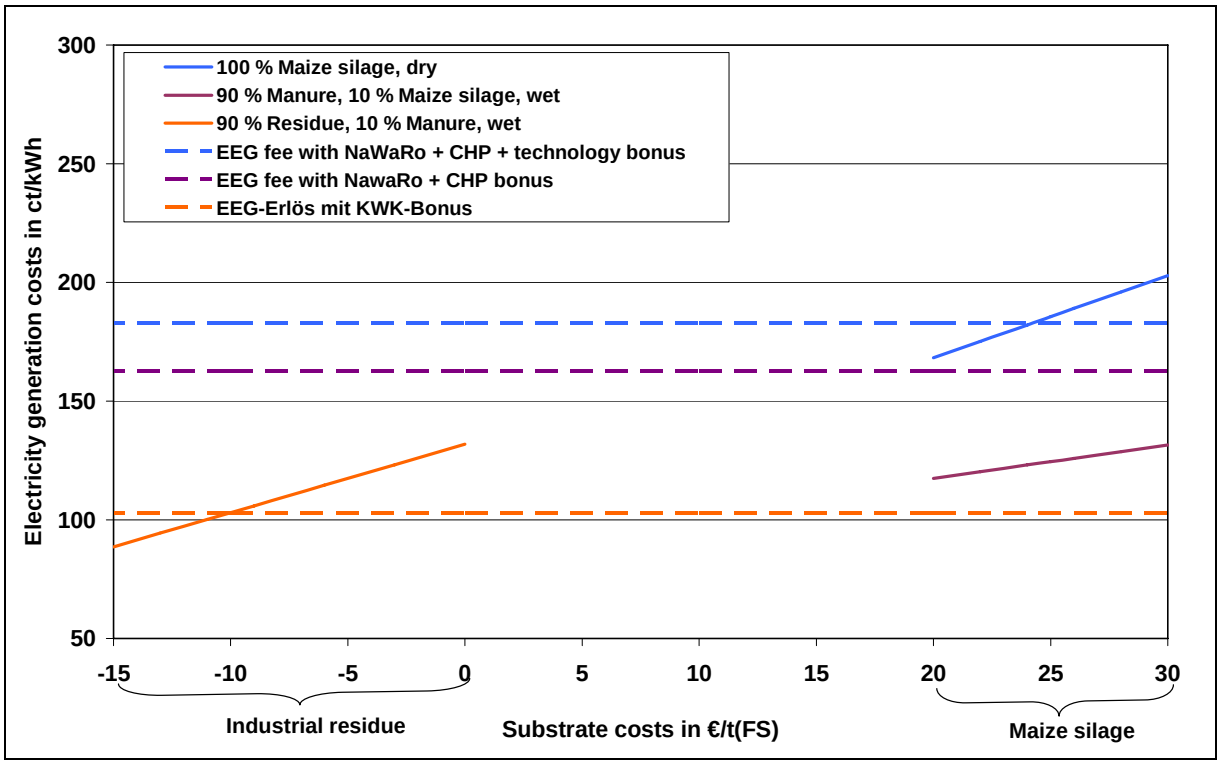


Fig. 8-5: **Reference figures for nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (nominal) for 0.5 MW_{el} biogas facilities using various substrates, depending on substrate costs (no procurement or transport costs were added for the use of manure; other parameters identical to those in Fig. 8-3 [23]**

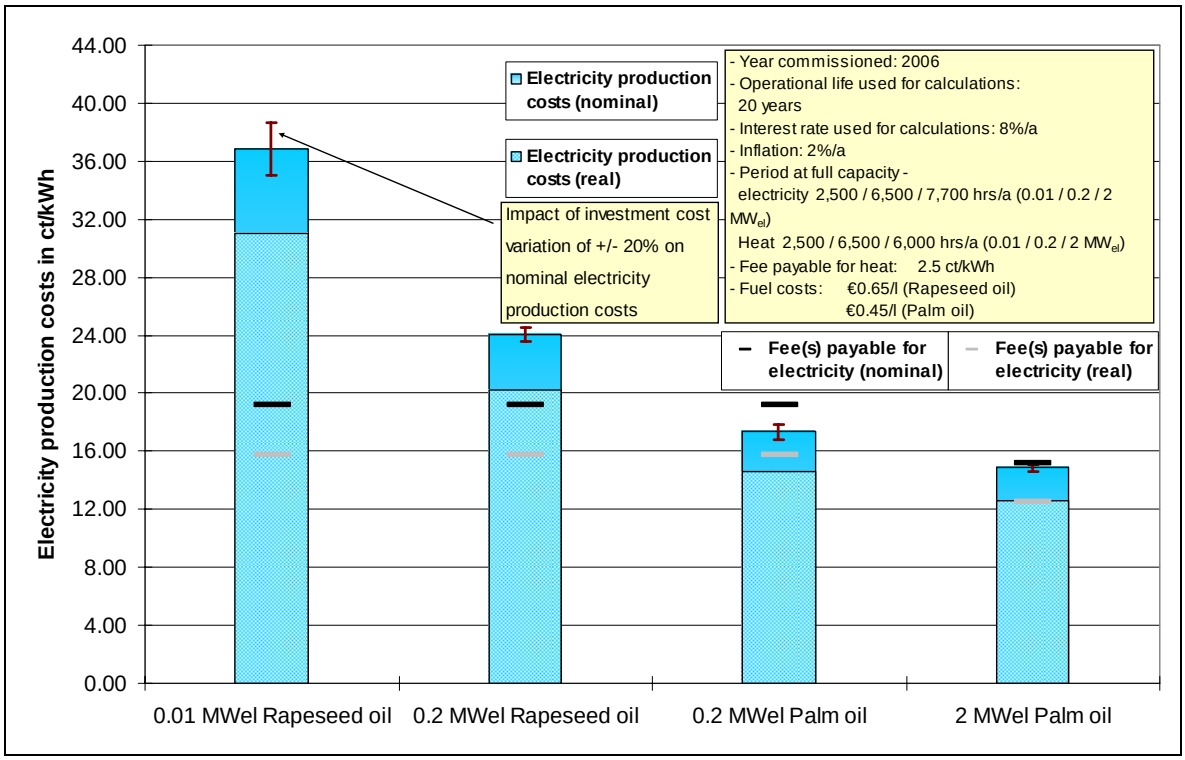


Fig. 8-6: **Reference figures: real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for small-scale cogeneration units which run on vegetable oil, after ZSW et al. 2007[12] [1]**

[12] See footnote 9 to Fig. 8-1 on page 82 and Chapter 15.1 page 163 ff.

8.2 Environmental evaluation of provisions under the EEG

The promotion of electricity production from biomass is governed by the objectives set out in Article 1 of the EEG; Article 8 of the EEG does not set out specific ecological requirements. However, impacts on nature and landscapes are caused – apart from the reduction of greenhouse gas emissions resulting from the substitution of fossil fuels and from energy recovery from slurry – by the installations themselves, by the increased use of forestry residues induced under Article 8(2) of the EEG, and by the production of bioenergy sources.

Biomass must be distinguished from other types of renewable energy sources with regard to its greenhouse gas emissions balance. Biomass is not CO_2-free but carbon-neutral. This means that when biomass is burned, the same amount of CO_2 is emitted as had been incorporated by the growing plant. In addition to this CO_2 cycle, climate-relevant emissions can occur within the process chains (e.g. nitrous oxide emissions).

For a comprehensive ecological analysis of electricity production from biomass one must distinguish in particular between biomass which is not explicitly generated with a view to energy recovery and biomass which is exclusively produced for energy recovery.

The first category contains biomass such as waste wood, slurry, and organic wastes from the food industry. Negative ecological impacts of the use of such biomass are very minor and are limited in particular to impacts arising from installations, such as the sealing of soil surfaces, barrier effects and habitat fragmentation for animals and plants, emissions of noise, exhaust fumes and dusts as well as landspreading of contaminated fermentation residues. Humans are primarily subjected to local impacts arising from increased traffic. However, in principle these impacts are assessed and minimised in the course of the required procedures and environmental assessments for obtaining planning permission. Moreover, these negative impacts also arise from conventional power plants and as these are substituted, no additional damage is caused.

When residues or farm wastes are used, the ecological impacts are normally more positive than in cases where biomass is specifically produced for energy production. This is particularly true with regard to avoiding greenhouse gas emissions. Additionally, energy recovery from slurry in biogas installations is of ecological benefit. Landspreading of slurry on arable land or grassland subsequent to biogas extraction results in lower emissions of methane than if the slurry was spread directly and methane is a clearly more damaging greenhouse gas than CO_2. Moreover, fermented slurry has a positive influence on soil quality and results in lower odour emissions.

The use of biomass generated in the course of landscape management activities is also of benefit from the nature conservation point of view. Such use is subject to high provision costs which can however be reduced in the course of increasing development of the infrastructure (regional facility mix for the recovery of all biomass factions, such as woody biomass, stalks and straw or herbaceous fuels with a high lignin content).

Apart from the impacts described above, the increased utilisation of small-sized timber and forest residues may remove valuable habitat structures. From the conservation point of view it is therefore of great importance that good forestry practice be employed in energy recovery from forest residues [24]. Overall, the exhaustion of the potential for energy recovery as induced by the EEG is currently at a low level. However, local negative impacts can arise where firewood utilisation, wood-based thermal power stations and other installations are developed in close proximity.

Electricity generation from biomass specifically produced for energy recovery may add further ecological impacts to those given above.

The production of agricultural biomass for energy recovery, which is being promoted for a variety of reasons, can lead to a narrowing of crop rotations and in turn to negative impacts on soils, water, air, fauna and flora (biodiversity) and scenic qualities of the landscape. Compared to agricultural non-use in particular, there is an increased use of fertilizers and pesticides. The increase in maize production for biogas generation is particularly significant in this regard. According to information from the German Federal Agency for Agriculture and Food (BLE) there has been an increase in the area used for the production of biomass crops (excluding grains) from 13,000 ha in 2004 to 158,000 ha in 2006 (for comparison: arable area in Germany is 11.9 million ha.). The greatest share of the area used for growing biomass crops was occupied by maize, with approximately 140,000 ha or 88% of the area used in 2006 [23]. This statistic includes only the biomass crops grown on set-aside land an on lands eligible for energy premia. However, biomass crops for use in biogas plants are also grown on other lands. An estimate produced in 2007 by the Institute for Energy and Environment [23], based on the substratum requirements of existing plants, states that it is likely that in 2006 as much as 400,000 – 500,000 ha of land was already being used for the production of biomass crops for biogas installations. Similarly, maize represents the greatest share in this estimate [23].

From the point of view of nature conservation and environmental protection it is the intensive production of silage maize in particular that is regarded as problematic. Potential consequences such as adverse impacts on soils due to compaction and erosion as well as the loss of biodiversity are countered by rules on good agricultural practice. Similarly, organic and mineral nitrogen fertilisers can have a negative impact on groundwater and can eutrophicate watercourses [25]. These impacts are particularly evident where the maize is not integrated into a crop rotation and where it is grown under unsuitable site conditions.

The current critical debate on the production of genetically modified crops is also connected to this issue. However, in the EU and thus also in Germany there are strict procedures for the approval of the cultivation of genetically modified crop cultivars which include an environmental risk analysis.

Further impacts on nature and landscapes arise where fallow lands are returned to production or where production is intensified again on lands previously used in an extensive manner. This can result in habitat loss for wild animals and plants and can endanger nests of meadow breeding birds as well as the raising of their young, especially where due to intensified production grasslands are cut earlier in the year.

In the future there may also be impacts on the scenic qualities of landscapes due to tall crops such as maize, Miscanthus, hemp (up to 4 m) or short-rotation coppice. At present such species and varieties are primarily still at the trial phase.

The growing of fast-growing short-rotation coppice crops is primarily being undertaken for research purposes on agricultural lands. This change in land-use can have an adverse impact on the scenic qualities of the landscape, but it can also have positive impacts on biodiversity. Stalks and straw generated in the farming sector are currently only used to a minor extent in heating installations.

In the area of liquid bioenergy sources for stationary applications, the use of palm oil in particular is of concern as it has been connected to the destruction of tropical rainforests. This is especially true in Indonesia and Malaysia which supply 85% of the world production of palm oil. The palm oil-based combined heat and power generation plants established in Germany by the end of 2006 require 340,000 tonnes of palm oil per year. This amount of palm oil equates to a production area of about 100,000 hectares and thus 1.5% of the production area under oil palms in Malaysia and Indonesia.

The cultivation of crop plants in Germany – regardless of whether they are used as food, feed, or energy source – is governed by the same guidelines for good agricultural practice. Compliance with production guidelines is systematically checked on an annual basis in the context of inspections regarding other obligations under EU direct payment schemes (cross compliance).

In conclusion it can be said that, regarding electricity generation from biomass specifically grown for this purpose, the existing rules and regulations governing farming practices in Germany, minimise negative ecological impacts. It should be examined in how far there is a need for action in this area. There is also a need for research in this field. A comprehensive ecological assessment is to take the positive ecological impacts into account, especially the reduction in greenhouse gas emissions.

8.3 Competition for land and resources

The increased use of biomass for energy can lead to competition for land and resources. In the domestic situation such competition is characterised by the limited amount of land available for cultivation and/or potential alternative uses for the substrates. In contrast, there is generally more land available in the potential export countries. Particular attention must be paid to sustainable production in these countries. The discussion on competition relates primarily to competition for agricultural lands and to economic alternative uses of wood.

In agricultural production there is still potential for increased biomass yield, for example by increasing yields per area, through increased use of the entire plant and through increased utilisation of residues and by-products. In the medium and long-term, the extension of biomass utilisation could lead to increased competition between the different recovery types for the limited agriculturally utilisable area. In some regions with high livestock concentrations and in areas dominated by feedstuff production this effect is already evident with regard to maize, which is used in both biomass plants and for livestock feeding. Improved production techniques and optimised technical processes amongst other things, as well as imports of sustainably grown biomass may in the future reduce competition for land.

The situation in the forestry sector is different from that prevailing in agriculture for a number of reasons.

Four different markets are in competition for wood:

- material use,
- heat generation,
- electricity generation,
- probably in the future: Fuel generation (second generation fuels).

These markets are in part supported through a variety of measures, in the material area mostly by way of investment aids and in the energy area through market incentives (e.g. EEG).

Naturally the greatest recovery interest relates to cheap biomass. Due to the broad spectrum of recovery options across a wide spectrum of wood types (e.g. round timber, industrial wood residue, forest residue) with different price tags, this is of special importance with regard to wood production. In mobilising these wood reserves, good practice requirements must be taken into account. After decades of falling prices in real terms in the wood sector, the market is now characterised by price increases. Further demand for wood may strengthen this trend. In this context it must be considered that re-use and recycling of wood in the sense of closed-loop cycling of materials is possible and is intensively practiced.

International situation

It can reasonably be assumed that in all industrialised and strongly oil-dependent countries there will be a growing interest in bioenergy. Despite country-specific differences in producer and buyer structures, the impacts with regard to competition for land and resources will be comparable to the national situation described above. This is also true for developing and newly industrialising countries. However, in developing countries the question of the displacement of food production as a result of the production of energy crops is particularly pressing. Especially in those countries which are dependent on food imports, the food supply situation may worsen if world market food prices rise. There is as yet little known about how the increased demand for bioenergy will impact on food security in developing countries and this question is the subject of current research.

The further development of price impacts resulting from the rise in biomass utilisation should be carefully monitored in order to be able to counteract potential undesirable market distortions.

8.4 Policy recommendations

We recommend retaining the EEG's general provisions for electricity generation from biomass, especially the structure comprising minimum fees and bonuses, but also propose some adaptations (see box).

The current payment system, with its capacity-based basic fee combined with various bonuses, takes account of the variety of production conditions and desired policy outcomes.

Due to the change in economic circumstances, we recommend that the fee payable for electricity from biomass facilities up to and including 150 kW_{el} in capacity be increased by 1 cents/kWh for both new and existing facilities.

Generating electricity from agricultural cultivated biomass presents a particular set of issues. For this type of facility, rising agricultural prices have had such a negative impact on economic viability that no additional optimisation of operations at such facilities can compensate for it. We therefore propose an increase from 1 to 7 cents/kWh in the NawaRo bonus for electricity from biomass, for both new and existing facilities with a capacity of up to 500 kW_{el}.

The introduction of the NaWaRo bonus has proved effective overall. We therefore consider that the level of fees payable to facilities of up to 5 MW_{el}, the distinctions between them and the operational requirements on them be retained for the most part. In isolated cases, problems have arisen due to the fact that the EEG contains only general requirements to fulfil the practical conditions for claiming the NaWaRo bonus. This has created a series of borderline cases in terms of potential fuels. For example, where vegetable oils have been traded on the world market, it is still unclear how proof can be supplied that the practical conditions for claiming the NaWaRo bonus have been fulfilled. Different legal opinions have also emerged as to the possibility of using various biogas substrates in cultivated biomass facilities. We therefore recommend that a list of recommendations/exclusions for the NaWaRo bonus be included in the EEG.

We consider the decrease in/levelling off of interest in manure fermentation in biogas facilities to be a negative development, especially since great potential for producing biogas from manure remains untapped. In order to counteract this development, we propose the following amendments to the EEG:

- An increase by an additional 1 cent/kWh in the NaWaRo bonus for electricity from biogas (from both new and existing facilities) in the capacity range up to and including 150 kW_{el}, where manure constitutes a steady minimum of 30 per cent (by volume or mass) of the total annual material fermented to make biogas, and
- The removal of dry fermentation from the list of technologies to benefit from the technology bonus, as the current provisions create a false incentive to replace even manure available free of charge with more energy-rich biomass (see below).

Increasing the minimum fee for facilities of up to and including 150 kW_{el} will favour the use of manure available locally.

The strict application of the principle of exclusive use to cultivated biomass employed in biogas facilities, and the payments made for this, means many by-products of arable farming are not used for energy, even though they arise in the immediate vicinity of a biogas facility. We therefore recommend that some flexibility be introduced to the current exclusive position. Further reasons for this include the rise in the price of energy crops and the need to use biomass more sensibly for energy. Certain plant by-products that are approved for fermentation in biogas facilities should be selected and listed. Their use in biogas facilities should have no, or limited, impact on the market. The biogas produced from these by-products should only be eligible for the basic fee. The NaWaRo bonus should remain limited to that proportion of the fuel which features on the list of recommended fuels. For accounting purposes, precise, traceable and transparent documentation is required as the basis for any payment due for that proportion of by-products fermented at a biogas facility.

In order to avoid false incentives, the NaWaRo bonus for electricity from burning wood payable to facilities of between 500 kW_{el} and 5 MW_{el} has been reduced to 2.5 cents/kWh in the version of the EEG currently in force. In particular, false incentives include the competition with materials recovery for certain types of wood. However, such incentives are not expected to arise where the wood is from landscape management or from short-rotation plantations. We therefore propose that a NaWaRo bonus of 4 cents/kWh be granted where these types of wood are used.

The extent to which potential conflicts of interest can be countered must be ascertained by creating a list of recommendations/exclusions. This should also be considered when any amendments are made to the Biomass Ordinance. In this context, the priority utilisation of residual materials is particularly important.

Experience of the CHP bonus to date has shown that this has only proved partially effective as an incentive for greater energy efficiency. In order to better harness the significant

potential for increased efficiency which has so far lain dormant in bioenergy facilities, and to further increase the proportion of combined heat and power generation, we recommend increasing the CHP bonus by 1 cent/kWh. So as to ensure that the CHP bonus only supports utilisation of heat where this makes sense from a renewable energy perspective, “combined heat and power” must be defined more precisely. The aim should be to grant the CHP bonus only to those uses of heat that actually help substitute for fossil fuels.

One factor cited as limiting the increased use of waste heat among biomass facilities subject to the EEG has been the restriction of the CHP bonus to facilities commissioned from 1 January 2004 onwards. In many cases this provision, which was intended to prevent false incentives, actually prevents a facility performing a sustainable switch from biomass to CHP generation. We therefore recommend that the scope of the CHP bonus be extended to include “existing facilities”, where the process of equipping these facilities to utilise waste heat occurs after the amended EEG comes into force.

The special status of vinasse generated at an agricultural distillery, which is considered to be a form of cultivated biomass for the purposes of the NaWaRo bonus, although it does not fulfil the general requirements for cultivated biomass, will no longer be necessary in the case of facilities commissioned after the amended EEG comes into force. We can safely assume that vinasse that has been generated at an agricultural distillery and for which no other use has been found is already finding its way to biogas facilities.

The technology bonus aims to make it easier to bring innovative, especially energy-efficient and therefore environmentally and climate friendly technologies and processes onto the market. We recommend that the technology bonus be retained in its present form, and adapted to current developments in technology. Many of the dry fermentation processes promoted by the technology bonus since 2004 can now be considered to have been introduced onto the market. We therefore propose to remove dry fermentation from the list of technical processes receiving special support. The preparation of biogas of the same quality as natural gas, which currently receives support, is intended to act as a particularly good means of permitting the energy efficient and climate friendly use of biogas. In order to ensure that this is the case, recent reports on energy and climate protection show that requirements on the energy efficiency of the biogas processing facility and on possible methane emissions from biogas processing should be introduced. We therefore recommend that the eligibility of processing biogas to the quality of natural gas for the technology bonus be dependent in future on compliance with upper limits on methane emissions and electricity consumption. In many cases, the same aims achieved by preparing biogas of natural gas quality can also be achieved by establishing biogas microgrids. We therefore recommend that the scope of the technology bonus be extended to cover establishing biogas microgrids in conjunction with biogas facilities, unless biogas microgrids can be promoted through investment in the context of the Market Incentive Programme for Renewable Energies (MAP) or the Joint Task of Improving Agricultural Structures and Coastal Protection (GAK).

The 20 MW (electrical capacity) upper limit on the scope of the EEG has proved counter-productive in a few isolated cases. This is because, in order to sidestep this upper limit, one smaller or even several small facilities have been constructed next to or in the immediate vicinity of each other in order to claim EEG payment, despite the fact that large biomass facilities would have made better technical and economic sense. We therefore propose to remove the 20 MW upper limit for facilities using combined heat and power generation from biomass commissioned after the EEG amendments. However, even then only that portion of the electricity fed into the grid which was produced by the capacity under 20 MW should be eligible for remuneration.

The progressive reduction (degression) in the basic fee payable to new facilities is currently 1.5% p.a. Yet we can safely assume that costs for the steel and energy required to construct such facilities will tend to increase yet further. Technical progress should not be expected to

compensate in full for this increase. In order to take this trend into account, and also to continue to exploit desirable potential for cost reductions, we recommend that the progressive reduction in the basic fee for new facilities be adjusted downwards slightly for facilities commissioned as of 2009, from 1.5% to 1% p.a.

So as to create a major incentive to continue refining the innovative technologies involved in waste heat and cultivated biomass use, and to reduce the associated costs, we also recommend – despite the increase in the bonuses – extending this progressive reduction of 1% to all bonuses in the biomass sector for facilities commissioned from 2010 onwards.

The clear increase in small-scale cogeneration units run on palm and other vegetable oils highlights the need to formulate sustainability criteria for the production of cultivated biomass. We must ensure that only biomass produced sustainably and in a manner compatible with nature conservation is eligible for remuneration as electricity from cultivated biomass. To that end, the power to lay down sustainability criteria should be enshrined in the EEG. In order to avoid any negative impact on nature and the environment, this power should encompass both countering negative trends relating to the importing of biomass which cannot be guaranteed to have been sustainably produced and addressing potential future issues which may arise. Until an effective certification system emerges to guarantee sustainable cultivation, electricity generation from palm and soya oils (particularly questionable energy sources) should not be eligible for the NaWaRo bonus.

Although the NaWaRo bonus makes a major contribution to protecting the climate and resources and to developing rural areas, there is increasing public debate about negative impacts on our landscape and natural environment from the intensive cultivation of biomass for electricity generation. It is therefore important to ensure that the targeted cultivation of bioenergy sources is compatible with nature conservation. The current policy toolkit provides a good basis for this. The provisions on good practice in agriculture and on the other requirements for direct payments from the EU (cross compliance requirements) are particularly useful, although unable in themselves to sufficiently reduce potential negative effects. We therefore recommend that the rules on good practice be reviewed regularly and adapted where necessary.

As the number of biogas facilities increases, it becomes increasingly important to reduce the amount of methane each one emits. We recommend ensuring in future that all possible, state-of-the-art measures be taken to reduce methane emissions. Introducing an obligation to cover post-digestion storage areas is particularly crucial.

Policy recommendations for the provisions on electricity generation from biomass (I)

Provisions within the scope of the EEG

- 1 ct/kWh increase, meaning the basic rate of remuneration for new and existing facilities with a capacity up to and including 150 kW_{el} rises to 11.67 ct/kWh

- Increase, from 6 to 7 ct/kWh, in the NawaRo bonus for biomass electricity from both new and existing facilities with a capacity up to and including 500 kW_{el}

- Additional increase of 1 ct/kWh in the NawaRo bonus for biogas electricity from both new and existing facilities with a capacity up to and including 150 kW_{el}, if at least 30% (by volume or mass) farm manure is used

- The principle of exclusive use is to be made more flexible for biogas plants using cultivated biomass: it should be possible for certain plant by-products which are not eligible for the NawaRo bonus to be used in conjunction with NawaRo biomass in future. These should be chosen on the basis of a positive list. However, entitlement to the NawaRo bonus should apply solely to the replenishable share of inputs used to generate electricity from biogas.

- Introduction of a 1% p.a. degression for all biomass bonuses which do not currently taper (the NawaRo, CHP and technology bonuses) for plants commissioned from 2010 onwards

- Increase in the CHP bonus from 2 to 3 ct/kWh. Definition of “combined heat and power” to be stated, thus preventing the inefficient use of heat

- Reduction in the degression for fees payable to new facilities in accordance with Article 8(5), from 1.5% to 1% p.a. (for plants commissioned from 2009 onwards)

- Increase in NawaRo bonus for electricity generated by burning wood from landscape management or short-rotation plantations, payable to facilities with 0.5-5 MW_{el} capacity, from 2.5 ct/kWh to 4 ct/kWh

- Removal of eligibility for NawaRo bonus for vinasse generated at an agricultural distillery, where this is used in new facilities.

Policy recommendations for the provisions on electricity generation from biomass (II)

- Scope of CHP bonus to be extended to facilities already commissioned, where the process of equipping these facilities to utilise waste heat occurs after the revised/amended EEG (based on this Report) comes into force
- Removal of 20 MW upper limit for new plants claiming payment under Article 8(1) EEG in conjunction with combined heat and power generation. However, only that portion of the electricity fed into the grid which was produced using the share of capacity under 20 MW_{el} should be eligible for remuneration
- Adoption of a "positive" and a "negative" list of recommendations and exclusions to establish the types of biomass acceptable for use in an EEG facility, as well as the statutory instrument issuing power necessary for amending the list. Potential conflicts of interest must be taken into account
- Exclusion of palm and soya oil from eligibility for an increased minimum fee in accordance with Article 8(2) (i.e. under the NawaRo bonus scheme) until an effective certification scheme to safeguard their sustainable cultivation is in place
- The Federal Government will also lobby at European level for the establishment of sustainability criteria for cultivated biomass. At the same time, the basis for authorisation should be introduced in the EEG for an ordinance to be enacted which defines the sustainability criteria for the cultivation of renewables. This should be agreed by the Federal Environment Ministry (BMU) and the Federal Ministry of Food, Agriculture and Consumer Protection (BMELV)
- Changes to the list of generation technologies to benefit from the technology bonus:
  a. *Removal of dry fermentation*
  b. *If it is not possible in practice to support biogas microgrids as part of investment programmes, then: inclusion of biogas microgrids in the list of technologies to benefit from the bonus*
- The bonus for feeding prepared biogas into the natural gas network is to be tied to compliance with upper limits on methane emissions and electricity consumption.

Policy recommendations for the provisions on electricity generation from biomass (III)

Flanking measures outside the scope of the EEG

- The rules on good forestry and agricultural practice are to be reviewed regularly and adapted where necessary
- Adoption of measures to reduce methane emissions from biogas facilities: especially crucial are the obligation to cover post-digestion storage areas, and the use of the methane thus captured for to produce energy
- Promotion of biogas microgrids via the Market Incentive Programme for Renewable Energies (MAP)/the Joint Task of Improving Agricultural Structures and Coastal Protection (GAK)
- Measures to be taken to increase the use of waste heat from biomass electricity generation
- Assessment of measures, for both existing and new facilities, aimed at taking account of the planned significant reduction in the threshold value for formaldehyde in the Technical Instructions on Air Quality Control, and the additional investments in pollution prevention technology that this will necessitate.

9 Electricity from Geothermal Energy (Article 9 EEG)

The 2004 revision of the EEG introduced greater differentiation between the fees payable for different facility capacities. This was intended to take better account of the higher costs associated with smaller facilities. The fees for facilities of under 20 MW_{el} in capacity rose significantly, as project plans and scientific studies had shown that the original fee, approximately 8.95 cents/kWh, was not sufficient to allow economically viable operation. Electricity from geothermal sources can now earn a maximum of 15 cents/kWh (see Table 9-1). The progressive reduction for newly commissioned geothermal facilities differs from that for the other branches of renewable energy in that it begins in 2010. Only then are a large number of geothermal facilities expected to exist.

Table 9-1: Key rules in the Renewable Energy Sources Act on payment for electricity from geothermal [6]

	Scheme of minimum fees for facilities commissioned in 2007 (basic figures for facilities commissioned in 2004 in brackets)	Remuneration period	Degression for newly commissioned facilities
Basic fee for facilities up to 20 MW_{el}	Capacity up to 5 MW_{el}: 15.00 cents/kWh (15.00 cents/kWh) Capacity from 5 MW_{el} to 10 MW_{el}: 14.00 cents/kWh (14.00 cents/kWh) Capacity from 10 MW_{el} to 20 MW_{el}: 8.95 cents/kWh (8.95 cents/kWh) Capacity over 20 MW_{el}: 7.16 cents/kWh (7.16 cents/kWh)	20 years + year of commissioning	1%, from 1.1.2010

9.1 Market development and electricity production costs

The production of electricity from geothermal sources is still in its infancy, despite the considerable potential which exists. To date, only one power station is in operation: in Neustadt-Glewe, near Schwerin, in Mecklenburg-Lower Pomerania. In 2006 its electrical capacity was 230 kW, and it fed around 0.4 GWh of electricity into the grid (see Table 9-2). This facility was converted from a geothermal heating plant which had been in operation since 1994. With the introduction of the EEG, the plant was extended to become a geothermal heat and power station, although the thermal water temperature of 98°C is very low, even for low temperature turbines.

By and large, firm plans for geothermal power stations were only made after the 2004 revision of the EEG. As these stations take a long time to implement – between 3 and 5 years – no other facilities are operational as yet. However, facilities are under construction in Landau, Neuried, Bruchsal and Unterhaching. The facilities in Landau and Unterhaching are expected to be commissioned in 2007. Around a dozen other projects in the Upper Rhine valley and the Southern German Molasse Basin are at various stages of practical development. Proof of the clear increase in numbers of facilities can be found in the exploration licences and concession areas issued by the local mining authorities. As at November 2006, 150 permits and licences had been issued: 75 in Bavaria, 50 in Baden-Württemberg, 22 in Rheinland-Palatinate and 3 in Hesse.

Table 9-2: Key features of developments in electricity generation from geothermal sources between 2003 and 2006, after [1,2,3,4]

	2003	2004	2005	2006
No. of facilities	0	1	1	1
Total installed capacity (MW_{el})	0	0.2	0.2	0.2
Annual new installations (MW_{el}/a)	0	0.2	0	0
Electricity generated from geothermal (GWh/a)	0	0.2	0.2	0.4
EEG payments (million €/a)	0	0.03	0.03	0.05
EEG fee (in cents/kWh)	0	15	15	15
Jobs [13]	No data	50	Approx. 50	Approx. 50

Because of its particular geological and economic situation, the Neustadt-Glewe cogeneration plant cannot be compared to the other power stations due to be commissioned in the two southern German regions in 2007 (see Table 9-3). It is not therefore possible to make reliable predictions of electricity production costs using this as a basis. Similarly, the calculations of economic viability for projects currently being implemented are relatively unreliable, as in all cases series of tests, tender processes etc. have yet to be completed. The outcome of these will affect electricity production costs. In general, it appears that electricity production costs depend heavily on the specific practical conditions on the ground, and can vary greatly even within a single region.

Table 9-3: Geothermal electricity facilities constructed and in construction

	Installed capacity	Drilling depth/ thermal water temperature	Commissioned
Neustadt-Glewe	0.230 MW_{el}/ ca. 3 MW_t	Approx. 2,250 m 95-98°C	2004
Unterhaching	3.36 MW_{el} 28 MW_t (first extension) 40 MW_t (second extension)	Approx. 3,300 m Approx. 125°C	2007
Landau	3.8 MW_{el} 3.0 – 5.5 MW_t:	3,000 m/3,400 m Approx. 150°C	2007
Bruchsal	0.5 MW_{el} 4 MW_t	Approx. 2,500 m Approx. 128°C	2008

Extensive research programmes underpin developments on this market. In the context of the Federal government's future investment programme (Zukunftsinvestitionsprogramm, ZIP) and energy research programme, technological developments have been and continue to be developed and tested in the aim of better harnessing potential geothermal energy sources. One aspect of this is the development and refinement of exploration methods from the fossil fuel sector; another is the development of components and suitable deep-hole drills which are already being used worldwide. Around 42 million euros in research funding were provided between 2003 and 2006.

Despite the significant hike in fees payable to facilities of under 20 MW_{el} contained in the 2004 revision of the EEG, sufficient growth was not achieved on this market. Project plans and scientific studies show that even the higher fee of 15 cents/kWh for facilities up to and including 5 MW_{el} in installed capacity only make operation economically viable where

[13] The number of jobs indicated by the statistics remains low; this may be due in part to the data collection methods employed.

intensive research funding is also supplied. The upward trend in drilling costs and lack of qualified drilling personnel also represent major obstacles. Since 2004, petroleum and natural gas prices have risen sharply, leading to a sharp increase in exploration activity in this sector. There is now a major shortage of drilling equipment and trained staff. As a result, drilling and drilling service prices have risen by over 30% in eighteen months. Prices are expected to rise by up to a further 20% over the next three years. Steel prices have also risen greatly. Since the underground part of a geothermal power station (drilling, drilling services, pipelines etc.) constitutes around 50 to 60% of the overall costs, some projects have already been put on hold due to the rise in costs. In such circumstances, only projects in the central Upper Rhine valley, with short drilling depths, and a few projects in the Molasse Basin in Southern Germany, have been implemented [1].

9.2 Environmental evaluation of provisions under the EEG

Our knowledge of the environmental impact of geothermal power stations is currently incomplete. The only reference materials we have are the results of the progress report by the German Bundestag's Office of Technology Assessment (TAB), entitled "Möglichkeiten geothermischer Stromerzeugung in Deutschland" (Opportunities for geothermal electricity in Germany), and those of a current research project on the lifecycle effects on the environment plus the impacts on humans, the landscape and the natural environment [26]. According to the above results, thermal water pipes can cause a warming of the area close to the surface. This is a localised effect, as the impact of the pumped or reinjected thermal water only applies to the immediate vicinity of the borehole, and thermal water pipes are usually laid along existing structures such as roads. We do not therefore expect any large-scale detrimental effects on soil or groundwater.

Since geothermal facilities have lower efficiency levels than conventional power stations, geothermal electricity generation is associated with large amounts of waste heat. Where water cooling is used, there is a possibility of warming up rivers and streams, to the detriment of plants and animals. However, the water authorities perform checks on the permissibility of such usage, usually placing conditions on any authorisation issued.

Humans may be temporarily exposed to increased noise while the borehole is drilled. This also applies to animals in protected areas. As noise protection and other relevant requirements often form part of the authorisation process, there is no danger of this causing harm.

The risks of pollutants entering the soil and groundwater, and of breaching different groundwater strata when drilling down, have been widely debated. However, there is no real environmental impact. Technical measures taken subject to mining legislation ensure that the upper groundwater strata used for drinking are sealed off while the borehole is being drilled. This excludes the possibility of polluting the groundwater and of breaching different water strata.

We do not currently see any need to act on reducing any negative impact on the landscape or natural environment.

9.3 Policy recommendations

We recommend retaining the EEG's general provisions for electricity generation from geothermal, but also propose some adaptations to the fee categories and rates of remuneration. We propose introducing additional support by means of a bonus for waste heat use and a bonus for non-hydrothermal technologies.

At present, most new facilities have an installed capacity of under 5 MW_{el}. Some facilities of between 5 and 10 MW_{el} are planned. Since we do not currently expect rapid growth in the size of facilities beyond 10 MW_{el}, the fee classes for geothermal power stations should be simplified, leaving two classes: "up to and including 10 MW_{el}" and "over 10 MW_{el}".

Because it is currently only economically viable to operate a geothermal facility with the help of substantial research funding, and considering that drilling prices have risen dramatically and the prospect of sufficient drilling equipment and trained staff being available lies several years in the future, we recommend increasing the fees payable. The fee payable for facilities up to 10 MW_{el} should be 16 cents/kWh (was: up to 5 MW_{el}, 15 cents/kWh; up to 10 MW_{el},14 cents/kW) and for facilities over 10 MW_{el} it should be 10.5 cents/kWh (was: up to 20 MW_{el}, 8.95 cents/kWh; over 20 MW_{el}, 7.16 cents/kWh. All figures for facilities commissioned in 2009).

The efficiency of geothermal projects can increase significantly if heat is utilised as well as electricity generated. Studies have shown that if heat is used via a connection to a local or district heating network, this can bring an increase of around 50% in CO_2 emission reductions. This would not be classed as "combined heat and power" in the usual sense, as the temperature level of the waste heat from such electricity generation is often too low to feed into a heat network. Part of the geothermal volume flow is used directly to produce heat and is not available for electricity generation. Thus the average electricity generation output from a CHP facility is reduced if it is primarily operated to produce heat. We therefore recommend that a heat use bonus of 2 cents/kWh of electricity be introduced for heat extraction.

Apart from geothermal energy generation from hydrothermal sources, which is possible in relatively few areas, significant further potential for utilising geothermal lies in the production of electricity and heat from hot rock (non-hydrothermal systems). The following technologies may be used for such production: enhanced geothermal systems (EGS), hot dry rock (HDR), stimulated geothermal systems (SGS), hot fractured rock (HFR), hot wet rock (HWR) and deep heat mining (DHM). These methods extract energy from the rock itself, largely independently of water-bearing structures. The rock is effectively used as a heat exchanger. However, utilising thermal water currently has clear cost benefits over generating electricity using these methods. Nevertheless, in the aim of eventually harnessing the considerable potential of such generation methods, we propose an additional technology bonus of 2 cents/kWh to support them.

Several accompanying measures should also be taken to ensure that geothermal potential is successfully tapped. Support for the construction of additional local and district heating networks will encourage the distribution and efficient use of the heat. As this support cannot be provided by means of EEG payments, other policy tools such as the Market Incentive Programme (MAP) should perform this role.

Research activities should be stepped up to accompany the introduction of geothermal projects onto the market. This research should focus in particular on advanced technologies, electricity generation at low temperatures and gathering geological information in order to optimise project planning.

There are also plans to offset the relevant exploration risk more satisfactorily. Despite all other survey methods, only drilling can ascertain whether or not the extraction rates and temperature that can be achieved in practice are sufficient to make a particular geothermal facility economically viable. As it costs between four and twelve million euros to sink a borehole, depending on its depth and degree of difficulty, a failed borehole represents a major financial setback. The Federal Environment Ministry is currently working with the KfW (German Bank for Reconstruction) and the private insurance industry on resolving this issue.

We would further recommend that particular drilling risks be covered by an investment cost subsidy for additional expenditure incurred due to the increased technical input required as a result of unfavourable geological circumstances (up to a maximum of 30% of overall drilling costs), payable via the MAP.

Policy recommendations for the provisions on electricity generation from geothermal energy

Provisions within the scope of the EEG

- Reduction in the number of capacity classes, from four to two, and increase in basic fees payable to facilities commissioned in 2009, as shown:

  Class 1: Share of capacity up to 5 MW_{el} 16 ct/kWh (currently 15 ct/kWh)
  Class 1: Share of capacity between 5 and 10 MW_{el}: 16 ct/kWh (currently 14 ct/kWh)
  Class 2: Share of capacity between 10 and 20 MW_{el}: 10.5 ct/kWh (currently 8.95 ct/kWh)
  Class 2: Share of capacity over 20 MW_{el}: 10.5 ct/kWh (currently 7.16 ct/kWh)

- Introduction of a 2 ct/kWh heat cogeneration bonus
- Introduction of a 2 ct/kWh technology bonus for non-hydrothermal technologies (may be claimed cumulatively with the heat cogeneration bonus).

Flanking measures outside the scope of the EEG

- Provision of support through other funding programmes for the development of local district and district heating networks to distribute the waste heat utilised
- Increased research activity, to focus in particular on advanced technologies (such as hot dry rock technology), electricity generation at low temperatures and gathering geological information in order to optimise project planning
- Creation of a fund to cover geological risks (the exploration risk). The Federal Government will contribute to this fund via the MAP.
- Particular drilling risks to be covered by an investment cost subsidy for additional expenditure incurred due to the increased technical input required as a result of unfavourable geological circumstances – up to a maximum of 30% of overall drilling costs for deep geothermal – payable via the MAP. Quality to be tested through the risk fund.

10 Electricity from Wind Energy (Article 10 EEG)

The 2004 revision of the EEG introduced greater differentiation into the provisions on payment for producing electricity from wind. Thus for the first time new provisions provided a financial incentive for repowering – replacing existing wind turbines with higher-performance modern turbines. The same revision removed the payment to turbines in unfavourable locations, where these turbines achieve less than 60% of the reference yield.

A tiered scheme of payment rates was introduced for offshore wind turbine generators in 2004; the rates vary depending on the distance from the coast and the depth of the water. In addition, the minimum period for payment of the higher initial fees was extended from 9 to 12 years, and the window for claiming under this provision was extended to include turbines commissioned before 31 December 2010.

The progressive reduction in fees for all wind turbine generators was increased from 1.5% to 2% p.a. in 2004.

Table 10-1: Key rules in the Renewable Energy Sources Act on payment for electricity from wind [6]

	Scheme of minimum fees for facilities commissioned in 2007 (basic figures for facilities commissioned in 2004 in brackets)		Remuneration period	Degression for newly commissioned facilities
Onshore wind farms	Initial fee: Final fee:	8.19 ct/kWh (8.70 ct/kWh) 5.17 ct/kWh (5.50 ct/kWh)	20 years + year of commissioning	2% p.a. from 1.1.2005
Offshore wind farms	Initial fee: Final fee:	9.10 ct/kWh (9.10 ct/kWh) 6.19 ct/kWh (6.19 ct/kWh)	20 years + year of commissioning	2% p.a. from 01.01.08
Specific provisions for onshore wind farms	• No obligation to pay fees for turbines which cannot achieve a minimum of 60% of the reference yield at a planned site. • Initial fee payable for at least 5 years and at most 20 years, depending on yield compared with reference site. • Remuneration period for initial fee extended by 2 months per 0.75% (or 0.6% for repowered turbines) by which the actual yield of a turbine stays below 150% of the reference yield. • In the case of repowered turbines, the period of initial fee payment will only be extended if the installed capacity of the turbine(s) replaced or modernised is increased by a multiple of at least three.			
Specific provisions for offshore wind farms	• Turbines commissioned before 31.12.2010 eligible for payment of initial remuneration for at least 12 years. • For turbines commissioned by 31.12.2010, extension of remuneration period for initial fee by 0.5 months for every nautical mile which the turbine stands from the coast in excess of 12, and by 1.7 months for each additional complete metre in depth by which the turbine exceeds 20 m.			

The reference yield model aims to permit wind turbines to operate throughout Germany, and therefore provides for fees which vary according to location. This means that farms at the best coastal sites only receive the higher initial fee for five years, whereas inland farms receive it for longer. At sites with a reference yield of just 60%, the initial fee is payable for up to 20 years. At sites with under 60% of the reference yield, no fee is payable. This reference yield system results in an estimated average remuneration period of around 16 years.

10.1 Market development and electricity production costs

At the end of 2006, a total of 18,685 wind turbines were operating in Germany, with an installed capacity of 20,622 MW. Newly installed capacity for 2006 stood at 2,234 MW. This is higher than that installed in 2005, but is due to catching up on 2005 installation. If we consider this fact, the basic trend is downwards. Whereas a total of 2,328 turbines were installed in 2002, with a capacity of 3,247 MW, the average for the years 2004 to 2006 lay at around 2,000 MW. One major reason for this is the reduction in land available for wind energy use. Local authorities have now completed their identification of suitable areas, conducted in the context of favouring wind turbines on greenfield sites. Most of the sites identified, especially at coastal locations, are now occupied by wind turbines. We can therefore assume that, over the next few years, the number of new onshore wind turbines will fall still further due to the increasing scarcity of suitable sites. Conversely, we expect the number of older turbines replaced by larger, higher-performance ones (repowering) to increase gradually.

In contrast, the situation as regards technological developments looks distinctly positive. Thus the average installed capacity of wind turbines erected in 2006 was 1.8 MW. More turbines in the 3 MW range with 90m rotor diameters and 150m overall heights have achieved economic viability on the basis of payments under the 2004 EEG. However, the recommendations issued in many *Länder* on distance from residential areas and turbine height limits are making the implementation of such projects more difficult.

Table 10-2: Key features of developments in electricity generation from wind between 2003 and 2006, after [1, 2, 3, 4]

	2003	2004	2005	2006
No. of turbines	15,387	16,543	17,574	18,685
Total installed capacity (MW)	14,609	16,629	18,428	20,622
Annual new installations (MW/a)	2,644	2,036	1,808	2,234
of which as a result of repowering (MW/a)	80,8	54	12	136
Average capacity of new turbines (MW)	1.552	1.696	1.723	1.848
Electricity generated from wind (GWh/a)	18,859	25,509	27,229	30,710
EEG payments (million €/a)	1,695.9	2,278.9	2,386.3	2,734
EEG fee (in cents/kWh)	9.06	8.93	8.76	8.90
Reduction in CO_2 emissions (in million tonnes/a)	16.1	22.0	23.5	26.3
Jobs		64,000	No data	82,100

Given suitable conditions, repowering will be the main future development in coastal regions. The scope of Article 10(2) EEG potentially encompasses 3,540 turbines, with a total capacity of 1,120 MW, which were commissioned prior to 31 December 1995 (in accordance with the requirements). Such repowering usually becomes economically viable once existing turbines are at least 12 years old, given the current conditions based on the fees payable under the 2004 EEG. In theory, 1,530 turbines were candidates for repowering at the end of 2005, yet only 18 were actually replaced – by six larger turbines. Similarly, in theory, 2,828 existing turbines were candidates for repowering at the end of 2006, yet only 79 were actually replaced – by 55 new turbines.

The great repowering potential which exists is not being sufficiently tapped at present, which means this is not currently a significant force on the market for wind power. Besides the economic causes, administrative and building law obstacles should also be cited as causative factors. Turbines constructed prior to 31 December 1995, and therefore prior to the amendment of Article 35 of the Federal Building Code (on favouring wind turbines in greenfield areas), are often sited outside priority areas. It is increasingly difficult to obtain building permission for new-technology equipment in the context of repowering such turbines, either because they are closer to residential areas than current regulations allow or because the local authorities in question have now designated priority areas elsewhere, and are therefore under no obligation to renew authorisations. The situation for wind turbines operating within priority areas is very different, as these basically have building permission in such areas. Yet here too, new spacing regulations and height restrictions are leading to a clear reduction in the amount of repowering potential currently harnessed. The requirement in Article 10(2) EEG to increase capacity by a multiple of at least three when repowering can only rarely be squared with these strict local rules, which are often no longer justifiable from the point of view of averting danger or preventing risks. Furthermore, the existing provisions on repowering contain an extension of the period for which higher fees are payable. This provides a financial incentive, the impact of which varies from location to location. The incentive is not sufficiently effective at onshore sites.

Table 10-3: Developments in the repowering of wind turbine generators in Germany between 2002 and 2006 [27]

	Existing turbines		Turbines after repowering		Repowering factors	
Year	No. of turbines	Installed capacity, in MW	No. of turbines	Installed capacity, in MW	Reduction in no. of turbines	Increase in capacity
2002	16	5.4	8	12.7	- 50%	x 2.4
2003	68	29.7	46	80.8	- 68%	x 2.7
2004	45	17.2	33	54.0	- 73%	x 3.1
2005	18	9.0	6	12.0	- 33%	x 1.3
2006	79	26.19	55	136.4	- 70%	x 5.2

The electricity production costs for wind power have fallen substantially since it first entered the market. The mid-rate of remuneration at the reference site, adjusted for inflation, shows that the amount payable in 2006 was 60% lower than the amount payable in 1991. If we retain the current provisions, the mid-rate of remuneration for the reference site will fall to 6.60 cents/kWh in real terms by 2010. This is equivalent to a further 14.9% fall compared to the reference year, 2006. In the recent past, both the specific cost of a turbine and additional investment costs, and therefore electricity production costs, have risen significantly. This is due in part to the strong rise in steel and copper prices over the past two years or so and the major increase in international demand for wind turbines, as well as the rise in interest rates. We therefore predict that the EEG fee will be insufficient for even today's best economic performers in economic terms, turbines with capacities of between 1.3 and 1.9 MW, at all but

a very few sites, as relatively high constant wind speeds would be required. Figure 10-1 illustrates this point [1].

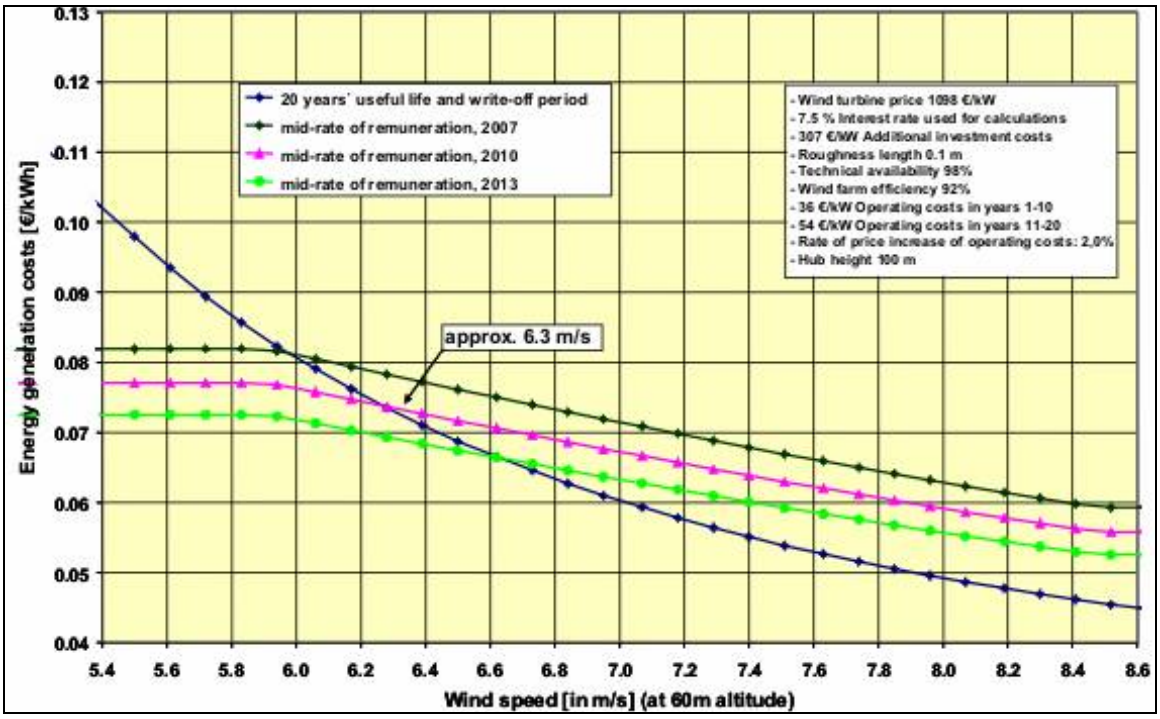


Fig. 10-1: **Reference figures for electricity production costs and mid-rate of payment as against site quality for wind turbine generators with capacities of between 1.3 and 1.9 MW at a hub height of 100 m, after ZSW et al. 2007 [1]**

Figures 10-1 to 10-4 show electricity production costs in relation to wind speed and hub height.

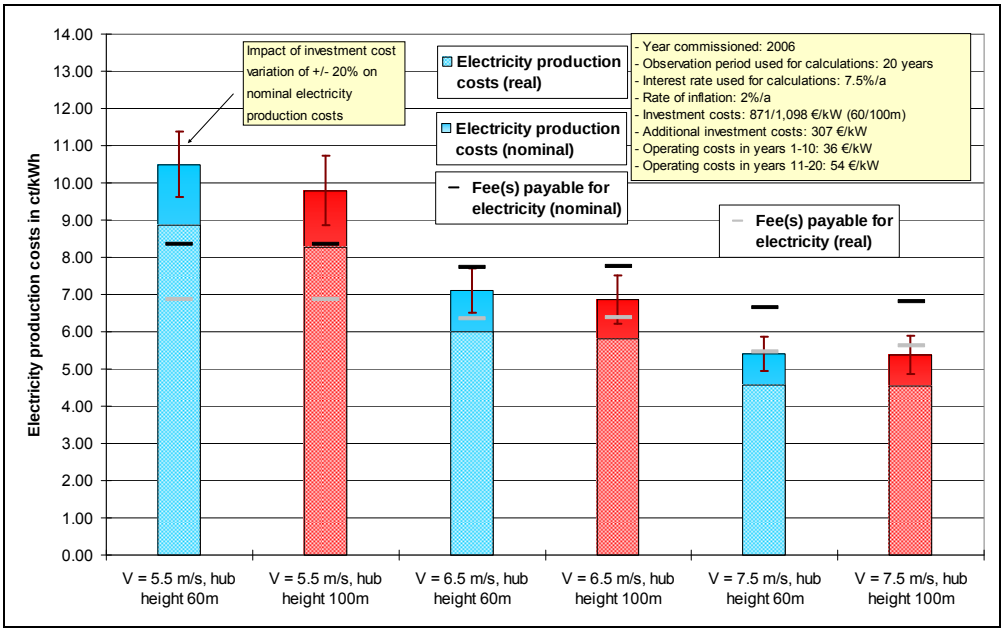


Fig. 10-2: **Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for wind turbine generators with capacities of between 1.3 and 1.9 MW, after ZSW et al. 2007[14] [1]**

[14] The costs are shown in real terms, i.e. adjusted for inflation, and as nominal figures without considering inflation. As the rates of remuneration under the EEG are nominal figures, these should be compared to the nominal electricity production costs. For completeness, inflation was also included on the income side (real

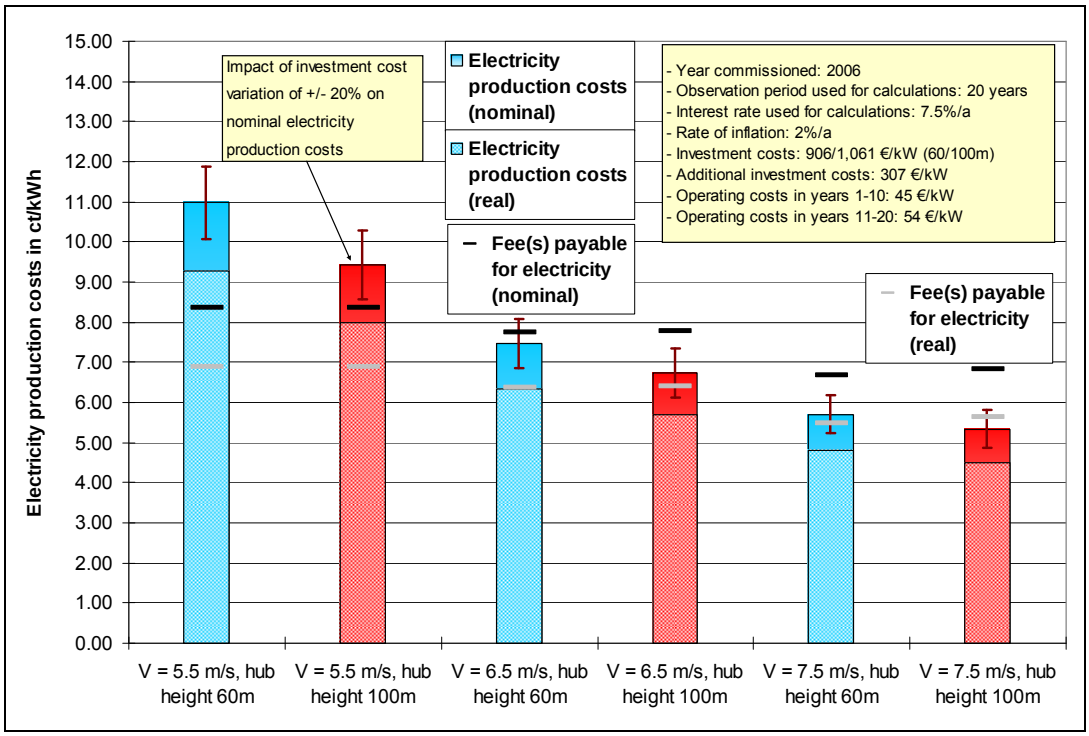


Fig. 10-3: **Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for wind turbine generators with capacities of between 2.0 and 3.0 MW, after ZSW et al. 2007[15] [1]**

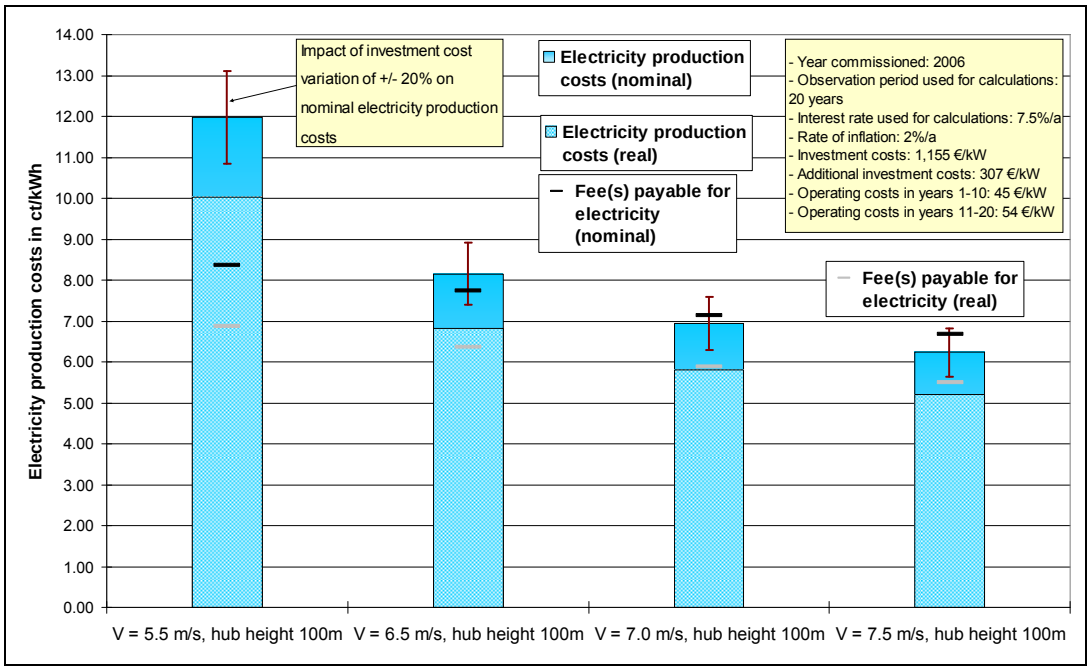


Fig. 10-4: **Reference figures for real and nominal electricity production costs for new facilities (commissioned in 2006) as against the mid-rate of remuneration (real and nominal) for wind turbine generators in the capacity class of over 3.0 MW, after ZSW et al. 2007[16] [1]**

payment). Real electricity production costs should therefore be compared with real payments and nominal electricity production costs with nominal payments. (See also Chapter 15.1 Page 163 ff.)

15 See footnote 14 to Fig. 10-2 on page 107 and Chapter 15.1 page 163 ff.

16 See footnote 14 to Fig. 10-2 on page 107 and Chapter 15.1 page 163 ff.

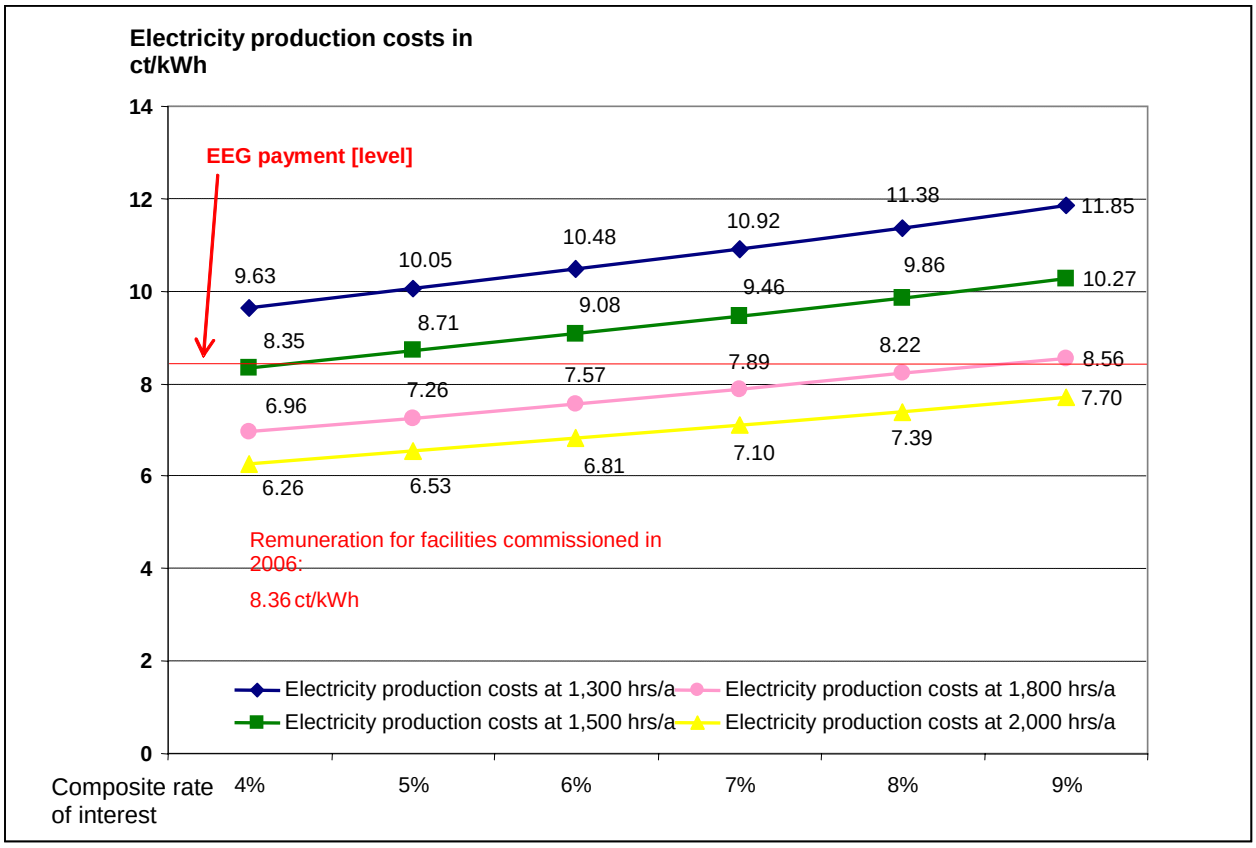


Fig.10-5: Electricity production costs for a 1.5 MW repowered wind turbine generator as against the interest rate and number of hours at full capacity, in cents/kWh, after IE/Prognos 2006 [14]

Progress is being made as regards the licensing procedures for offshore wind energy projects in Germany. As at 31 June 2007, a total of 18 licences had been granted for the construction and operation of offshore wind farms in Germany's exclusive economic zone. Fifteen of these licence recipients, which total 1,100 turbines with an overall capacity of approximately 5,000 MW, are situated in the North Sea. Three other projects, with a total of 240 turbines and a capacity of around 1,200 MW, are situated in the Baltic Sea. Furthermore, within the 12 nautical mile zone, the “Baltic I” project in the Baltic Sea has also obtained building and operation permission. In terms of technology, there have also been some major achievements, as prototype wind turbines in the 5 MW class with rotor diameters of up to 126 m and hub heights of 125 m have been developed by Enercon, Repower Systems and Multibrid. At present, Enercon favours installing such turbines onshore. In summer 2007, BARD Engineering is expected to launch another 5 MW turbine, developed primarily for offshore use.

Despite the licences issued, these offshore projects have been postponed repeatedly. On top of difficulties with the authorisation of cable routes and the development of production-ready offshore wind turbines in the 5 MW class, the financing of these projects has also increasingly encountered obstacles. Only with the entry into force of the Infrastructure Planning Acceleration Act (*Infrastrukturplanungsbeschleunigungsgesetz*)on 17 December 2006 did conditions improve significantly, as transmission system operators were obliged to bear the cost of connections from the offshore transformer substation to the onshore grid connection point. This meant the average EEG fee of around 8 cents/kWh over 20 years was at least reasonable for a few projects situated close to the coast. However, due to the clear cost increases, particularly since the end of 2006, and to risks which are only now quantifiable, the final project costs are not clear, particularly during the installation and commissioning stage.

The first clear costings will be available once the first projects in Germany are a reality, in 2008/09.

However, on the basis of the initial tender processes and contractual negotiations for a variety of projects, including the offshore test park in the North Sea, it is now possible to make more reliable cost estimates than it was in late 2006. This is because project implementation activity (i.e. actual tender processes and negotiations) has been stimulated by improvements in the economic position based on the new conditions for grid connection contained in the German Energy Industry Act (EnWG) for projects where construction begins by the end of 2011. As these cost estimates became more reliable, it was established that the projects are now up to 50% more expensive than they appeared to be in the 2006 cost estimates. Thus overall costs have risen, despite the fact that the 2006 Infrastructure Planning Acceleration Act has removed the cost of grid connection from the equation.

One key factor behind the changes in cost estimates is that offshore wind power in the conditions prevailing in Germany with regard to water depth and distance from the coast is effectively a completely new type of wind generation, involving both innovative technology and new categories of risk. This type of generation does not exist in any neighbouring European countries. The risks associated with it, plus the current surge in worldwide demand for all the necessary components, have driven up costs substantially as described. What is more, at present the 5 MW turbines and support structures are still manufactured individually, and are therefore relatively expensive. Significant economies of scale are only expected to apply from an installed capacity of between 2,000 to 3,000 MW.

Table 10-4: Reference figures for electricity production costs for two models of an offshore wind farm comprising turbines in the 3 MW and 5 MW classes respectively (commissioned in 2007) [1]

	Model 1: offshore wind farm with turbines in the 3 MW class at 20 m depth	Model 2: offshore wind farm with turbines in the 5 MW class at 30 m depth
Overall investment	2,625 – 2,895 €/kW	3,010 – 3,230 €/kW
Operating costs: 1st decade 2nd decade	 108 €/kW 134 €/kW	 108 €/kW 134 €/kW
Finance	Project financing	Corporate financing
Interest rate used for calculations	8.15%	9.05%
No. hrs at full load	3,800 hrs/a	4,000 hrs/a
Useful life	20 years	20 years
Electricity production costs, 1st – 12th year	*12.67 – 13.63 ct/kWh*	*13.36 – 14.09 ct/kWh*
Electricity production costs, 13th – 20th year	*5.39 ct/kWh*	*5.28 ct/kWh*

Table 10-5: Overview of remuneration for offshore wind power in selected EU Member States [1]

Country	Remuneration	Comment	No. wind farms	Capacity (MW)
Denmark	Nysted II; Horns Rev II (Tender process 2006 – construction planned for 2010) 6.7 – 6.95 ct/kWh (approx. 14 years)	Grid system operator provides grid connection	8	416
France	13 ct/kWh (10 years), then reduction depending on site quality	Provisions include compensation for inflation	0	0
UK	13.9 ct/kWh (approx. 6 ct/kWh for certificates + approx. 7.4 ct/kWh market price for electricity + 0.5 ct/kWh tax relief)	€14.8 million subsidy per wind farm in "Round 1"	6	329
Netherlands	15.7 ct/kWh (9.7 ct/kWh for certificates (10 yrs) + approx. 6 ct/kWh market price)	€27 million subsidy for Egmond aan Zee wind farm	1	108
Spain	Proposal as at March 2007 Min. fee 7.125 ct/kWh Max. fee 16.4 ct/kWh of which Max. subsidy = 8.43 ct/kWh Max. electricity price = 7.97 ct/kWh	Subsidy granted on a project-by-project basis, may be lower for some projects. If the electricity price exceeds the stated value, the basic price will be lowered accordingly.	0	0
Germany	6.19 ct/kWh (20 yrs) + 2.91 ct/kWh (first 12 years + site-specific extension)	Grid system operator provides grid connection (two single prototypes in harbour area)	2	7

Given the above findings, the current conditions mean that very few offshore wind farms will become reality in Germany in the next few years besides the offshore test park, and that the country will therefore clearly fail to meet the objective, as stated in the Infrastructure Planning Acceleration Act, of an installed capacity of 1,500 MW by 2011. This is the conclusion reached by the KPMG market study entitled "Offshore-Windparks in Europa" (Offshore wind farms in Europe), published in October 2007 [28]. If we compare rates of remuneration for the offshore sector in Germany with those in neighbouring European countries (see Table 10-5), clear differences emerge. Besides the higher rates of remuneration in other countries, it is also clear that the funding there focuses on the first decade of the project life cycle. Given this situation, developments in offshore wind power will therefore be concentrated primarily in the rest of Europe. KPMG concluded that there is therefore a risk of Germany, a wind energy pioneer, being left behind by future developments in the offshore market.

10.2 Environmental evaluation of provisions under the EEG

Onshore wind turbines are amongst the renewable energy technologies whose impacts on nature and landscapes have been studied most intensively. In Germany there is an established set of instruments for the avoidance and reduction of impacts on the natural environment and on residents and recreationists resulting from noise, shadow flickering, reflection, beaconing, infrasound and ice throw. From the point of view of nature conservation the provisions of the EEG in conjunction with spatial development law and nature conservation law have largely proven successful and can be upheld.

In recent years new research results have been obtained on birds and bats, showing displacement effects from wind turbines for some resting migratory bird species. The overall impacts on breeding birds (displacement effects, disturbance) are lower in comparison. For most bird species, average collision rates are very low, but there are knowledge gaps regarding night-time migrations. However, for individual species, especially birds of prey and seagulls, collision rates are high. This is particularly a problem with regard to red kites as approximately half of the world population breeds in Germany. Less systematic research has thus far been devoted to collisions with bats. However, the research on hand and data from the "Nationwide database of collision victims at the Brandenburg Ornithological Station" suggest that bats suffer more strongly from collisions with wind turbines, especially near forest sites, than had previously been assumed. There is still a significant need for further research concerning the importance of these collisions with regard to species protection. In general however, negative impacts on birds and bats can always be reduced significantly through early and cautious site selection.

Impacts on nature and landscapes are caused primarily by the 3,540 wind turbines erected prior to December 31, 1995, as a relatively high proportion of these are located outside areas zoned as suitable areas (*Eignungsgebiete*) or priority areas (*Vorranggebiete*). In a suitable planning environment, repowering can contribute to replacing individually sited turbines which are causing problems for nature conservation and landscape aesthetics with facilities at low-conflict sites. In this context it should be pointed out that the regulations on maximum heights and minimum distances set out in the *Länder* decrees may prove to be impediments not only from the economic point of view (see above) but also from the point of view of nature conservation, if existing end-of-life turbines can not be replaced by plants at lower-conflict sites.

The targeted offshore wind energy utilisation was combined with extensive ecological back-up research on impacts on the marine environment. One must differentiate between the impacts of the construction and operation of offshore wind farms and of feeder cable routes leading towards the coast.

Observations during the construction phase of the Danish offshore wind farms at Horns Rev and Nysted showed negative reactions of harbour porpoises regarding their acoustic activity as well as behavioural reactions including a significant decrease in numbers. The noise tolerance of harbour porpoises in terms of construction noise has not been fully researched. However, research into this issue is currently underway in the context of a research project financed by the German Federal Environment Ministry (BMU) and results will shortly be available. In order to protect noise-sensitive marine mammals, the German Federal Maritime and Hydrographic Agency (BSH) routinely prescribes in its notifications of approval that state-of-the-art methods involving minimum noise must be used in construction, and that measures to minimise ambient noise and prevent damage must be taken. During the operation phase, harbour porpoises do not generally avoid the wind farm sites. While no change to the numbers of harbour porpoises within the Horns Rev wind farm was recorded, the area of the Nysted wind farm, currently in its second year of operation, continues to be frequented less often by harbour porpoises than before.

Damage to the fish fauna resulting from sediment disturbance during the course of construction work is minor. However, it is not clear in how far sound-intensive construction noise may impact negatively on the fish fauna. A positive effect would appear to be the fact that offshore wind farms can serve as refuges for shoals of fish, provided fishing is not possible there.

The impacts on benthic biocoenoses resulting from the plants' foundations etc. are limited locally and therefore rather minor. Provided relevant protection measures are taken, no

large-scale negative impacts on fish, birds, or marine mammals are to be expected from cable laying.

The impacts on habitats of sea bird species as a result of disturbance during turbine operation varies substantially. Based on aerial census flights at existing wind farms it appears that a few sensitive species avoid these sites while other species show no change or even frequent the farms more strongly for resting and feeding purposes. Based on existing research in offshore wind farms in coastal areas, the risk of collisions between migratory birds and wind turbines is low for a number of bird species (e.g. common scoters, eider ducks) as the installations are evaded even in dark nights. For offshore wind farms it can be assumed that in unfavourable weather conditions there is a higher theoretical risk of collisions between migratory birds and wind turbines; however, there are as yet no practical findings in this regard. At present it is not possible to assess whether the beaconing of sites has an attractant effect on birds.

The risk of collisions with ships is subject to intensive assessment in the approval of offshore wind farms. Attention is paid to sufficient distances from main shipping lanes. Moreover, the Federal Maritime and Hydrographic Agency (BSH) is working on a protection and safety strategy which will optimise and coordinate the various protection and safety measures in view of the pending offshore development.

Due to a lack of completed offshore wind farms for Germany, no final assessment can as yet be made with regard to negative impacts on the marine environment; there is still a significant need for further research. Based on experience from offshore wind farms in other countries it can be said that, given current knowledge and provided that suitable preventive and mitigation measures are taken, significant negative ecological impacts are not to be expected from individual projects. However, there are still knowledge gaps regarding the evaluation of cumulative effects of a greater number of large-scale projects.

The “distance and depth” bonus provided under Article 10 (2), which is designed to facilitate the development of distant marine waters for offshore wind energy utilisation, also takes the precautionary principle into account in so far as it gives economic incentives to maintaining the conservation importance of coastal waters, of feeding and resting habitats for birds and of bird migrations. However, the designation of suitable areas of offshore wind farms, the approval process including the Environmental Impact Assessment and the speedy implementation of spatial planning are of critical importance. From the point of view of nature conservation a major achievement of the 2004 EEG amendment is that electricity generated by wind turbines will not be paid for if these are built in a marine protected area, i.e. a Special Area of Conservation or a Special Protection Area within the Natura 2000 network, which cover a total of more than 30% of the exclusive economic zone (EEZ). This provision effectively implements the objective to protect nature and the environment pursuant to Art. 1 of the EEG. (Sources : [29, 30, 31, 32])

10.3 Policy recommendations

We recommend retaining the EEG’s general provisions for electricity generation from wind, but also propose some adaptations (see box). Due to the rises in costs which have occurred for investments, mainly caused by the increases in raw material prices and in world market demand, an annual degression of 2% (nominal)/4% (real) in the fees for new turbines will no longer be balanced out by advances in productivity. We therefore recommend setting the degression at 1 to 2%.

The 60% rule, i.e. the removal of payment for turbines at unfavourable sites which achieve less than 60% of the reference yield, has proven its worth. The rule is necessary for an efficient expansion of wind power use, and should be retained as it stands.

To safeguard the security of the grid and of supply, wind turbines are increasingly asked to perform system services which were previously undertaken by the conventional plants (see Chapter 5.2 for grid integration and feed-in management; see Chapter 12 for storage technologies and system integration). The aim of this is to ensure that the legislator's desired rise in the proportion of the energy supply coming from renewables across all the voltage systems and grid regions is achieved, while also maintaining grid security and achieving a maximum of independence from conventional power plants, both while the grid is operational and while there is a fault. A range of studies and investigations have identified the need to refine the standards for turbines. So, for example, new features in turbines based on advanced technical developments in power electronics may secure improvements in the turbines' integration into the grid. In particular, modern wind turbines are now able to assist with voltage and frequency control, to work with a broader range of reactive power and self-stabilise where there is a fault on the grid (known as "fault ride-through").

It is also technically possible to retrofit some of the wind turbines already in operation. This would make sense in terms of increasing grid stability. Part one of the German Energy Agency's study on the grid recommends it. There is no need for this retrofitting to be carried out across the board, or to achieve the same technical standard as new turbines, because the number of existing turbines is limited and given that repowering will occur in future. Since a compulsory introduction of the features described above is not being considered for existing turbines – in order to protect the current portfolio – a bonus should be created for voluntary technical retrofitting where turbines are not being repowered (if repowered, they would have to fulfil the same new technical requirements as new plants). The operators of wind turbines commissioned between 1 January 2002 and 1 January 2009, when the amended Act comes into force, should therefore receive an increase of 0.7 cents/kWh in their fee, provided their turbines are retrofitted by 31 December 2010. This retrofitting should ensure that the plants in question are able to fulfil the requirements for voltage and frequency control. These technical requirements are lower than those recommended for new plants, but sufficient to achieve the improvement in wind turbine performance in case of a fault on the grid required by part one of the German Energy Agency's study on the grid. However, since technically the grid does not need all existing wind turbines to be retrofitted, the bonus should be conditional on the grid system operator supplying a certificate stating that retrofitting the plant in question is worthwhile for the grid.

In order to safeguard grid stability in the medium to long term and utilise the potential of plant technology to increase grid stability, the remuneration for all new onshore wind turbines should be tied to the three technical features once the amended Act comes into force (as of 1 January 2009). It should be compulsory to possess these three features. However, additional expenditure will be required for this. A check is currently being conducted in the context of the EEG revision as to whether the initial rate of payment for all new onshore wind turbines should be increased by 0.7 cents/kWh to compensate for this, and allow for the new turbines to be equipped with the technology. This increase could be cut gradually over time, or simply removed for turbines commissioned after 1 January 2014.

The conditions for repowering should be improved. Although the administrative and legal obstacles are mainly associated with regulations in the *Länder*, measures could be taken in the EEG to tap more effectively into the available potential for repowering. We therefore recommend reformulating the fixed commissioning period for existing turbines built before 31 December 1995 as a sliding scale in Article 10(2) EEG, and applying it to all turbines that have been operating for at least ten years. Furthermore, we do not believe that the requirement for installed capacity to treble can be fulfilled in practice with building law as it stands. Capacity should therefore merely be required to double. In addition, an upper limit of a five-fold increase in capacity should be introduced in order to prevent any potential abuses and false incentives. These requirements to increase capacity should be met by decommissioning an existing turbine or, if one is not enough, several existing turbines. Thus

the introduction of a limit on capacity increase may simultaneously act as an incentive to reduce landscape intrusion by removing a number of scattered wind turbines.

At the same time, there is a need to improve support for repowering. The current provisions in Article 10(2) EEG provide no financial incentive to decommission existing onshore turbines. In order to provide an effective incentive for this, the high fee payable to the existing turbine should be transferable to the new turbine for the period for which the existing turbine would have been eligible for it under the EEG at that same site, a period during which the operator of the existing turbine would generally have claimed the higher fee were it not for this transfer possibility.

Additional solutions for developing repowering lie outside the scope of the EEG. In particular, only the *Länder* and local authorities, and not the central government, can include provisions (such as height restrictions and spacing regulations) in regional and land use plans. Insufficient use is being made of the benefits of repowering (reducing landscape intrusion, increasing the energy yield from a decreasing number of turbines, sometimes increasing the revenue from trade tax, sometimes providing system services, etc.) and the tools to implement it at *Land* and local level. The Federal Ministry of Transport, Building and Urban Affairs and Federal Environment Ministry should therefore draw up a joint plan to expand the development of repowering on the basis of the current construction and regional planning legislation, as well as engaging in a dialogue with the *Länder* and local authorities. It is particularly important to draw up guidance and recommendations on the opportunities under planning law to support repowering, involving a presentation of best practice, which can be made available to the *Länder* and local authorities as they develop their own repowering strategies. The Ministries should look into the concerns expressed by many local authorities that repowering will temporarily reduce their tax revenue.

An assessment should also be made of how to raise levels of interest within local communities in the establishment or renewal of wind turbines (repowering).

No offshore wind power is actually being used in Germany at present, due to the financial situation. The new situation has emerged since the Infrastructure Planning Acceleration Act came into force. The conditions are satisfactory for a few projects located close to the coast, but not for the main areas of German offshore wind power development. Under these conditions, cost reductions will only be achieved once experience has been gained of using the technology in Germany, and once mass production of the foundations and turbines employed is established. We therefore recommend the following new payment structure for offshore wind power:

- The initial rate of payment should be increased to between 11 and 15 cents/kWh (this is a range – firm figures would be supplied on the basis of an up-to-date calculation of economic viability). This provision is necessary in order to foster initial experience in the industry and kick-start developments in German offshore generation. To offset this, the next level of payment should be reduced from 5.95 cents/kWh to a maximum of 3.5 cents/kWh. This payment structure (where the initial fee is raised and the subsequent fee lowered) is in line with international experience and the usual conditions for financing and tender processes.
- Consideration should be given to postponing the deadline for the start of degression from 1 January 2008 to 1 January 2013. In order to reflect the cost reduction effects expected to arise, the fee should be reduced progressively by 5 to 7% a year from 2013. The actual rate of degression should be examined and established alongside the initial level of payment.

These recommendations are based on initial experiences in the offshore test park and in project financing for forthcoming advanced offshore wind parks in Germany, as well as experience gathered abroad. When better estimates are available of the cost structures of

the German projects – i.e. as the projects are implemented – the rates of payment and degression should be adjusted accordingly. The proposed changes in payment structure should be introduced retroactively with effect from 1 October 2008 to ensure that the offshore test park launched by the Federal government can indeed be built.

A provision was introduced by the Infrastructure Planning Acceleration Act into Article 17(2a) of the German Energy Industry Act (EnWG) on the transmission system operator's responsibility for connecting offshore wind farms to the grid. This can be deemed a success, even though only a few months have passed since it was introduced. This provision is needed to accompany the EEG. However, according to Article 118(7) EnWG, it only applies to offshore wind farms built before 31 December 2011. In order to guarantee that it is possible to coordinate the grid connection of all offshore wind farms, even those built after that date, and ensure an environmentally and financially sound combination of the various transmission lines, without placing the burden of grid connection costs on the wind farm operators, thought should be given to extending the period for which this provision applies.

Finally, no fees should be levied to begin with on the use of federal waterways in the construction and operation of offshore wind turbines. This provision should apply for as long as payment for electricity is received under the EEG. The relevant administrative regulation issued by the Federal Waterways and Shipping Board on responsibility for user fees (VV-WSV 2604, Version 2007.1) will therefore need to be amended to provide an extra incentive during the initial phase of the offshore wind farm's existence. In the context of the next round of amendments to the EEG in four years' time, we can examine the need for and scope of this exemption for offshore turbines commissioned after the current amendments.

Policy recommendations for the provisions on electricity generation from wind (I)

Provisions within the scope of the EEG

- Check whether the payment system can be optimised (maximum period for higher initial fee, then lower final fee). The aim is to create an incentive for repowering and/or for direct sales of electricity from wind power.
- Setting the degression for payments to new onshore wind farms at 1 to 2% p.a. (for facilities commissioned from 2009; to be clarified in EEG amendments)
- Grid stability to be increased by means of improvements in the technical properties of onshore wind farms:
  - Consider making payments to new wind farms conditional on compliance with certain technical requirements – for performance when there is a fault on the grid, and for voltage and frequency control – from 1 January 2009. Assess the associated 0.7 ct/kWh rise in the initial fee necessary for all onshore wind farms commissioned by 31 December 2013, unless these farms are already under an obligation to fulfil the above requirements
  - Introduction for a limited period of a bonus of 0.7 ct/kWh for technical retrofitting to ensure voltage and frequency control in existing facilities commissioned between 1 January 2002 and the date on which the Act enters in to force, provided the grid system operator supplies a certificate stating that retrofitting the plant in question is worthwhile for the grid.
- Improvement of the repowering incentive in Article 10(2):
  - Replacement of fixed calendar for eligibility with a sliding scale (existing turbines must have been operating for at least ten years)
  - Reduction in the capacity increase required, from three-fold to two-fold; introduction of a five-fold increase upper limit
  - Introduction of a provision on transferring the fee payable for the existing turbine to the repowered turbine.

Policy recommendations for the provisions on electricity generation from wind (II)

- Improvements to payments to offshore wind farms under Article 10(3):
  - Increase in the remuneration rate for the first 12 years for all farms commissioned from 1 August 2008, from 8.74 to 11-15 ct/kWh (exact level to be established in EEG amendments); reduction in the (lower) final fee from 5.95 to 3.5 ct/kWh
  - Consider postponing the deadline for the start of the degression from 1 January 2008 to 1 January 2013. Increase the degression to 5 – 7 % p.a. (actual figure to depend on the remuneration rate and the above-mentioned deadline).

Flanking measures outside the scope of the EEG

- The Federal Ministry of Transport, Building and Urban Affairs (BMVBS) and Federal Environment Ministry (BMU) should draw up a joint plan, with the involvement of the Federal Ministry of Food, Agriculture and Consumer Protection (BMELV), to use construction planning law to expand the development of repowering. Dialogue is to be initiated with the *Länder* and local authorities, so as to dismantle administrative obstacles (such as spacing and height restrictions)
- Drafting by the BMU and BMVBS, with the BMELV and with the involvement of the *Länder* and of local-authority associations, of hints on repowering including examples of best practice
- Assessment of how to increase the interest of local communities in the establishment or renewal (repowering) of wind farms (BMU, BMF)
- Check on the need to extend the period allowed in Article 118(7) of the Energy Industry Act (construction commencing by 31 December 2011) for the grid system operator to take over the grid connection to offshore wind farms
- Planning measures to be implemented swiftly in Germany's exclusive economic zone.

Policy recommendations for the provisions on electricity generation from wind (III)

Flanking measures inside or outside the scope of the EEG

- Waiving of fees on the use of federal waterways in the construction and operation of offshore wind farms. This should apply for as long as payment for electricity is received under the EEG
- The need for and scope of this exemption for offshore farms commissioned after the current amendments should be examined in the context of the next round of amendments to the EEG, in four years' time.

11 Electricity from Solar Radiation (Article 11 EEG)

The rules on payment for electricity generated from solar radiation were adjusted on 1 January 2004 by the Interim Photovoltaics Act in order to compensate for the end of the support provided under the “100,000 Roofs” programme for solar electricity in the second half of 2003. The rates of payment were increased and distinctions made between the different capacity classes. In addition, a bonus was introduced for building integrated photovoltaic systems, i.e. mainly for facades, to create a particular incentive to tap the potential of this source in view of its higher electricity production costs.

At the same time, the previous link in the EEG between the obligation to pay fees and both the capacity of an individual facility (up to a maximum of 5 MW_p; the “$_p$” stands for “peak” and denotes the maximum capacity, given a reference figure for solar irradiation of 1,000 W/m^2) and the total capacity of all PV facilities (up to a maximum of 1,000 MW_p) was abolished.

Table 11-1: Key rules in the Renewable Energy Sources Act on payment for electricity from solar radiation [6]

	Scheme of minimum fees for facilities commissioned in 2007 (basic figures for facilities commissioned in 2004 in brackets)	Remuneration period	Degression for newly commissioned facilities
Facilities attached to or integrated on top of buildings or in noise protection walls	Capacity up to 30 kW_p: 49.21 ct/kWh (57.40 ct/kWh) Capacity from 30 kW_p to 100 kW_p: 46.82 ct/kWh (54.60 ct/kWh) Capacity over 100 MW_p: 46.30 ct/kWh (54.00 ct/kWh)	20 years + year of commissioning	5% p.a. from 1.1.2005
Building integrated photovoltaic (PV façades)	Bonus for facilities not built on/as roofs: an extra 5 ct/kWh		
Facilities attached to or on top of built structures (e.g. earthworks) and other developed land (e.g. paved-over land or land formerly used for other purposes)	37.96 ct/kWh (45.70 ct/kWh)	20 years + year of commissioning	5% from 1.1.2005 6.5% p.a. from 01.01.06
Particular requirements	• The bonus for facilities attached to buildings is not subject to degression. • The claim to payment for facilities not attached to or on top of built structures primarily constructed for purposes other than the generation of electricity from solar radiation is subject to certain conditions. • Facilities not attached to or on top of built structures are only eligible for payment where they are commissioned prior to 1.1.2015.		

Particular requirements apply to facilities not mounted on or integrated on top of buildings. Payment for electricity from facilities mounted on or integrated on top of built structures such as roads, landfill sites, noise protection walls or storage/stockpiling/parking sites is made at a much lower rate. The same is true of freestanding systems; the previous capacity restriction

of 100 kW_p per facility was lifted in the revised 2004 EEG. In order to prevent an uncontrolled proliferation of freestanding facilities, which could have negative consequences for the environment, certain conditions were associated with their construction. Thus for example a legally binding land-use plan (*Bebauungsplan*) is required, and the land used must be either paved-over, converted (from open-cast mining, slag heap or military use) or consist of grassland previously used for arable farming.

The degression (tapering) in rates of payment for new, building-mounted facilities was retained at 5% p.a., although it was raised to 6.5% p.a. for other facilities as of 1 January 2006. Freestanding systems are only eligible for payment if they are commissioned before 1 January 2015.

11.1 Market development and electricity production costs

Solar electricity generation in Germany is currently restricted to photovoltaics. Since 2004, photovoltaic facilities have been expanding rapidly: by the end of 2006, Germany had seven times as much installed capacity as in 2003. In this context, only those facilities connected to the electricity grid – around 200,000 – are relevant. These make up about 98% of all installed capacity.

The majority of grid-connected PV capacity, 65%, is situated in the two most southerly *Länder*, Bavaria and Baden-Württemberg. This is primarily due to the levels of solar irradiation there, which are approximately 15% higher than the German average.

Table 11-2: Key features of developments in electricity generation from photovoltaic facilities connected to the grid between 2003 and 2006, after [1, 2, 3, 4]

	2003	2004	2005	2006
Total installed capacity (MW_p)[1]	408	1,018	1,881	2,831
of which freestanding systems (MW_p)	17	60	113	187.6
Annual new installations (MW_p/a)	150	610	863	950
of which freestanding systems (MW_p/a)	4	43	54	74.6
Solar electricity generated (GWh/a)	313	557	1,282	2,220.3
EEG payments (million €/a)	153.67	279.99	663.60	1,176.80
EEG fee (in cents/kWh)[2)]	49.05	50.31	51.79	53.00
CO_2 emissions reduced (in million tonnes/a)	0.2	0.4	0.9	1.516
Jobs	No data	17,400	No data	26,900

1) The "$_p$" stands for "peak" and denotes the maximum capacity given a reference figure for solar irradiation of 1,000 W/m^2

2) The rise in average payment is a result of the large-scale new build of facilities, which receive higher levels of payment than existing facilities. Because the rates of payment will be progressively reduced, this rise is only a temporary phenomenon.

To date, developments in the market have mainly been concentrated on roof-mounted facilities. Of the photovoltaic capacity newly installed in 2005, an estimated 40% was in facilities of between 2 and 10 kW_p in the private housing sector, and 50% was in roof-mounted facilities of between 10 and 1,000 kW_p in capacity on blocks of flats, public and commercial buildings. Agricultural applications have proved particularly attractive, due to the comparatively large roof spaces available on freestanding buildings such as barns and the favourable financing conditions specific to this sector.

Building integrated photovoltaic facilities are currently insignificant in number/size, as the current EEG bonus of 5 cents/kWh is insufficient to compensate for the higher levels of specific investment and lower electricity generation yields achieved because of the suboptimal orientation of the facilities, especially in the case of smaller facilities. There is also currently insufficient recognition of PV modules as “building materials delivering additional benefit” which replace other materials. However, this is due in part to the fact that other applications are more profitable.

Freestanding facilities currently hold a market share of under 10%. The provisions in the new 2004 EEG for freestanding systems have created a major market for the sale of thin film photovoltaic cells. This shows that the support for photovoltaics provided in the EEG has meant a rapid conversion from products in research and development to industrial applications.

Strong growth in recent years has made Germany the world’s most important photovoltaics market, with a global market share of over 50%. Domestic production has so far been unable to meet the associated excess demand, but it is estimated that well over a billion euros have been invested in building new production capacity in Germany, at all levels of value creation, to meet the current excess demand. At present, around 50 companies are in operation, throughout the value chain (silicon, wafers, cells, modules, inverters and other system components). In the thin film technology sector alone, production sites with a total capacity of 360 MW_p are planned for 2007 and 2008, spread across ten projects and a variety of technologies. In addition to this, the leading German manufacturers in the crystal sector are aiming for an increase in capacity of at least 600 MW_p. This development continues to benefit regions in eastern Germany in particular. German manufacturers, and also companies manufacturing photovoltaic production plants, are competitive internationally and increasingly active outside Germany. Thus, despite the rapid growth in the overall size of the world market, German solar cell manufacturers increased their market share to over 20% in 2005. German manufacturers of photovoltaic production plants lead the global marketplace, with their strategic alliance building and use of existing sales channels allowing them to offer turnkey production facilities. Some companies hold global market shares of over 50%, and earn more than half their total turnover from photovoltaic production plants in Asia.

Electricity production costs for photovoltaic facilities fell by around 60% between 1991 and 2003. Of that fall, around 25 percentage points’ worth occurred between 1999 and 2003. Even after 2003, double-figure increases in annual productivity were achieved. However, the excess demand and silicon shortage meant that this did not result in a drop in prices. The high increases in productivity and newly-established, modern and innovative manufacturing processes lead us to conclude that production costs for PV modules have been falling steadily. However, it is not possible to quantify this fall due to the large number of stages in the value chain and the variety in corporate structures. At present, developments in investments vary widely depending on area of application, technology and producer company. The variety is particularly great in the sector for small facilities for private households. We can take 5,000 €/kW_p as a reference figure, with a possible variation of up to 30%. The range is not so great among larger facilities: for capacities of between 10 and 50 kW_p, it lies at around 4,700 €/kW_p. The lowest costs are experienced by large, freestanding facilities of over 1 MW_p: around 4,000 €/kW_p, and sometimes lower.

The resulting electricity production costs are shown in Fig. 11-1 [1]. These costs are largely equivalent to the EEG feed-in fee for roof-mounted and freestanding facilities commissioned in 2006. The economic viability of façade-mounted facilities is mainly dependent on the type of façade elements they replace. In the case of the small facility shown, PV modules are fitted as a curtain wall, and therefore relatively low bonuses have been assumed for replacing conventional building materials. This means it is not economically viable to operate. For the larger façade facility, the PV modules (partly) replace a glass front. Depending on the level of bonus, this can be an economically attractive option.

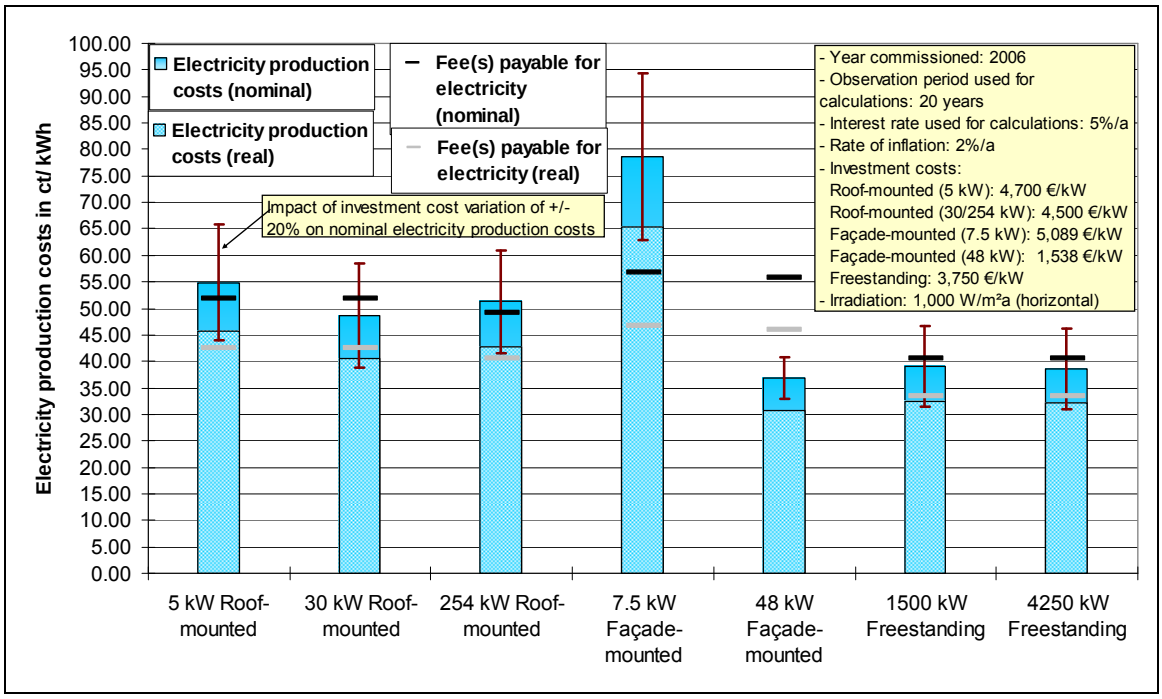


Fig. 11-1: Reference figures for electricity production costs for typical photovoltaic facilities[17] [1]

The operator structure, type of financing and interest rate all have a significant impact on the electricity production costs and economic viability of photovoltaic facilities. For private individual operators, the projected rate of return is often not as important as other motivational factors, such as environmental protection. The calculations are therefore based on the conditions for issuing loans under the KfW Förderbank (German Bank for Reconstruction promotional bank) programme for solar power generation, through which private facilities may be fully financed, up to a maximum of 50,000 euros. The nominal interest rate at the end of 2006 was between 3.45% and 4.15% p. a. Even if the current trend is for interest rates to rise, an interest rate for calculation purposes of a nominal 5%/real 3% would appear to be sufficiently attractive to stimulate investment.

In the case of commercial investments, equity capital of around 25 to 50% is usually required. This range results from the available financing options, or from the site of the facility (e.g. former East or former West Germany). Credit interest rates at the end of 2006 were around 3.5 to 4.5% p. a. (nominal), depending on the outside financing arrangements and the creditworthiness of the borrower. The estimated rate of interest applied to equity capital, 6.5 to 7.0% p. a. (nominal), is relatively low compared to other renewable technologies, and is realistic as investments in photovoltaic facilities are assessed as reasonably low risk. A composite interest rate of 5% (nominal)/3% (real) was therefore applied in the calculations.

If we apply these rather conservative assumptions, it is clear that the fees payable under the Renewable Energy Sources Act generally allow optimised photovoltaic systems to operate economically and, given favourable conditions, higher profits can be achieved than calculated. Only for small building-integrated facilities is the 5 cents/kWh EEG bonus insufficient. It should be noted when considering these results that cost benefits due to

[17] The costs are shown in real terms, i.e. adjusted for inflation, and as nominal figures without considering inflation. As the rates of remuneration under the EEG are nominal figures, these should be compared to the nominal electricity production costs. For completeness, inflation was also included on the income side (real payment). Real electricity production costs should therefore be compared with real payments and nominal electricity production costs with nominal payments. (See also Chapter 15.1 Page 163 ff.)

increases in productivity in the industry and an increase in market volume since 2003 have not meant a fall in prices, due to the excess demand and silicon shortage.

Further developments in PV technology, especially in terms of energy- and economic efficiency, are being driven forward at some speed by the Federal government's support for research. Between 2002 and 2006, the government invested around 300 million euros in projects and institutions in the photovoltaic sector.

11.2 Environmental evaluation of provisions under the EEG

Any impact of photovoltaic facilities on the landscape and natural environment is from the construction of freestanding facilities. Specific investigations have been conducted into these since the 2004 EEG entered into force [33, 34].

In terms of bird habitats, many species can use the spaces between and around freestanding facilities for hunting, feeding and breeding. The PV modules do not act as obstacles to birds of prey while hunting, and often act as lookout or singing perches. There is no indication that birds are disturbed or dazzled by reflected light. In theory, if a project is planned for open country which is valuable as a bird habitat, then this area may lose its value as a resting and nesting site, e.g. for sensitive meadowbird or resting waterfowl species, because of the modules' silhouette effect disturbing and scaring the birds. In practice, however, this does not occur as the legislator has used Article 11(3) EEG to tie payment for electricity from freestanding facilities to authorisation in the form of a legally binding land-use plan (*Bebauungsplan*) or planning permission, in order to protect sensitive areas. Furthermore, under Article 11(4) EEG, facilities must be built on already sealed, converted or arable land (this currently applies to 50% of freestanding facilities). Indeed, where sites for freestanding photovoltaic facilities are in extensive use, as is usually the case, and especially where they are located in otherwise intensively cultivated agricultural landscapes, they could become valuable habitats for bird life, such as skylarks, grey partridges or yellow wagtails.

There is no indication that large and medium sized mammals fundamentally avoid freestanding photovoltaic facilities. However, most of the operational premises are fenced off to prevent theft. This might interrupt connected areas and migration corridors, thus creating a barrier effect, especially for larger mammals.

Landscape intrusion is a possibility that cannot be ruled out. Particular long-distance effects may occur wherever a facility covering a large area is not shielded and is therefore visible, such as with sites on or near slopes. Dazzling effects due to reflected light are not significant, as these disappear even a short distance away due to the strong diffusion of light by the surface of the modules. Overall, the soil compaction which occurs during the construction phase and the soil surface sealing associated with facilities with concrete foundations affecting a maximum of 5% of the overall surface area do not constitute a significant negative impact, also when compared to other renewable energy plants.

Finally, in a comprehensive environmental analysis, the potential release of toxic substances must be cited as a risk. This is specifically associated with thin film photovoltaic technology, as it contains the heavy metal cadmium. However, any release, which could endanger humans, is impossible as the cadmium in the material is insoluble. What is more, in a fire the compound cadmium telluride (CdTe) will only melt at over 1,000 °C and will therefore be enclosed in glass which has already melted. In conjunction with the decision to invest in a CdTe thin film cell production plant in Frankfurt an der Oder, it was established that the modules erected in Germany will be recycled. This was also a requirement incorporated into the KfW's conditions under the ERP environmental protection and energy saving programme when it financed solar parks that use CdTe technology. The industry is currently drawing up a plan for the recycling of all technologies.

11.3 Policy recommendations

We recommend retaining the EEG's general provisions for electricity generation from solar radiation, but also propose some adaptations (see box). It should be noted that the photovoltaics sector is still developing. The future domestic expansion activity predicted by the Federal Environment Ministry's Lead Scenario 2006 (BMU Lead Study 2007 [5]) assumes annual new build will decrease gradually, but in any event remain sufficient to ensure that a strong domestic market remains dynamic and that further progressive reductions in costs continue apace. However, global growth rates would need to remain between 25 and 30% for at least a decade in order to reduce costs in line with the assumed learning curves. We expect notable success in manufacturers' international business to begin by 2010 at the latest, once the measures and policy tools currently being decided in other countries come into full effect. Thus it remains essential that the German market in the sector is sufficiently substantial. The continued successful industrial application of research findings is equally important, as technological innovations underpin the maintenance and expansion of German companies' keen international competitiveness.

In view of the unexpectedly dynamic expansion of manufacturing capacity, a five-fold increase in production volume in Germany since 2004 and the associated advances in technology, we can assume that manufacturing costs for photovoltaic facilities in Germany have fallen in line with the industry learning curve calculated from previous figures. Furthermore, the size of the market has increased sixfold since 2004, bringing further cost reductions due to economies of scale.

According to large companies worldwide, including some German companies, and based on sector analysis, further cost reductions of between 7 and 10% a year to 2010 are considered possible. We propose, given this situation, that the fee payable for roof-mounted and freestanding facilities be lowered by 1 cent/kWh on a one-off basis for 2009, and the degression increased by a moderate amount. The degression for roof-mounted facilities should be raised from its current 5% p.a. to 7.0% p.a. from 2009 and 8% p.a. from 2011 for newly commissioned facilities. The degression for freestanding facilities should be raised from its current 6.5% p.a. to 7% p.a. from 2009 and 8% p.a. from 2011 for newly commissioned facilities.

We do not expect this to have a major negative impact on the sector, as apart from anything else companies will have sufficient time to adapt to the change in circumstances. The higher degression will create an incentive to reduce electricity production costs significantly over the next few years. Furthermore, given favourable irradiation conditions as experienced in southern Europe or the southern United States, competitive electricity costs, some under 10 cents/kWh, could be achieved in facilities connected to the grid by as early as 2015. If that were the case, a market could operate in these places without additional financial support and open up interesting possibilities for German companies. This would help the EEG steer the industry towards successful new business abroad. However, accompanying measures would also be required to prevent companies moving abroad altogether.

With regard to the graduated levels of fees payable according to capacity, it has emerged that the investment costs for very large facilities, mainly built on the flat roofs of industrial buildings, are not significantly different to those for freestanding facilities. In order to take sufficient account of this, the capacity classes should be adjusted accordingly. We recommend that a capacity class be introduced for facilities of over 1,000 kW_p. The initial fee payable to this class should be 34.48 cents/kWh in 2009; subsequently, the fee should be subject to the degression applicable to building-mounted facilities. This represents a reduction of 7.31 cents/kWh in the fee payable to roof-mounted photovoltaic facilities with a capacity of over 1,000 kW_p.

Freestanding facilities should continue to receive support until 1 January 2015. These facilities have helped stabilise the expansion of the market in its early days, and provided major public inspiration. They have helped gather documented experience which will be valuable for future solar park project development, including in relation to the export market. For example, the Spanish market consists almost exclusively of large freestanding facilities. What is more, freestanding facilities open up great potential for product standardisation, pilot innovative products, especially in the thin film sector, and make major contributions to fulfilling cost reduction potential. Any shift among facilities of this size towards using roofs (the average installed capacity for a facility in 2006 was 2.65 MW_p) will necessarily be limited, as the supply of appropriate roofscapes is relatively small and may not be structurally suitable/suitably designed for large PV facilities.

Policy recommendations for the provisions on electricity generation from solar radiation

Provisions within the scope of the EEG

- Reduction of 1 ct/kWh in the basic fee payable for roof-mounted and freestanding facilities (commissioned in 2009)
- Increase in the degression rates for roof-mounted facilities under Article 11(5), from 5% p.a. to: 7.0% p.a. from 2009; 8% p.a. from 2011
- Increase in the degression rates for roof-mounted facilities under Article 11(5), from 6.5 % p.a. to: 7 % p.a. from 2009; 8 % p.a. from 2011
- Introduction of a new capacity class for roof systems with over 1000 kW_p, and reduction in the remuneration rate from 41.79 to 34.48 ct/kWh for facilities commissioned in 2009 (this takes into account the 1 ct/kWh reduction in 2009).

12 Storage Technologies and System Integration

The use of renewables for power generation results in new requirements for transmission and distribution grids, because they predominantly produce electricity in decentralised generating units and are therefore not necessarily compatible with existing transmission grids that were developed against the background of large, central generating units. Biomass, geothermal energy and hydropower are base load-capable and controllable based on demand, while wind and solar energy fluctuate throughout the year and on a daily basis. Unforeseen fluctuations are balanced using balancing energy. With an increasing proportion of renewables for power generation demand for balancing energy will grow further. At present balancing energy is provided by fossil fuel power plants and pumped-storage hydropower plants, and increasingly also through load management and decentralised plants. Increasingly new storage technologies are coming on stream that are able to provide balancing energy regionally where feed-in fluctuations occur.

The use of storage technologies should be considered as part of a comprehensive modernisation process that is taking place in view of a strong increase in the proportion of renewables. The use of flexible power plant technologies that can be controlled rapidly and with minimum loss, particularly gas turbines and CCGT power plants, and coupling of different renewable energy carriers leads to reduced demand of the energy system for storage capacity. Further development processes will simplify the integration of fluctuating supply, for example

- Significantly improved forecasting techniques for wind energy and PV supply;
- Increasing number of wind facilities with advanced control strategies;
- Optimised utilisation of the grid infrastructure, for example overhead line monitoring;
- Increased integration of load management;
- International electricity transfer offering more opportunity for balancing and buffering; and
- Further measures such as increased flexibility of schedule notifications and a national or European balancing energy market.

At the same time the use of storage systems should not only be regarded in conjunction with fluctuating supply, but also in conjunction with the development of the wholesale market (see Chapter 12.2), with plans for future power plant sites, and with the expansion of the German grid. For logistical and technical reasons a number of large coal-fired power plants are clustered along the German coast. The disparity between such plants and consumption centres increases the pressure on the grid infrastructure and therefore on the available capacity for the transmission of fluctuating electricity.

12.1 Current state of energy storage technologies

Various storage principles are available (Fig. 12-1). Electrical energy can be converted to heat and stored in the form of steam, for example. It can be transformed into potential energy (pumped-storage hydropower plants), kinetic energy (flywheel storage), or pressure energy (compressed-air storage) and then converted back into electricity. Electrical energy can also be converted into chemical energy and stored in batteries or – by means of electrolysis – as hydrogen. Electrical energy can be stored directly in superconducting magnetic storage media or capacitors.

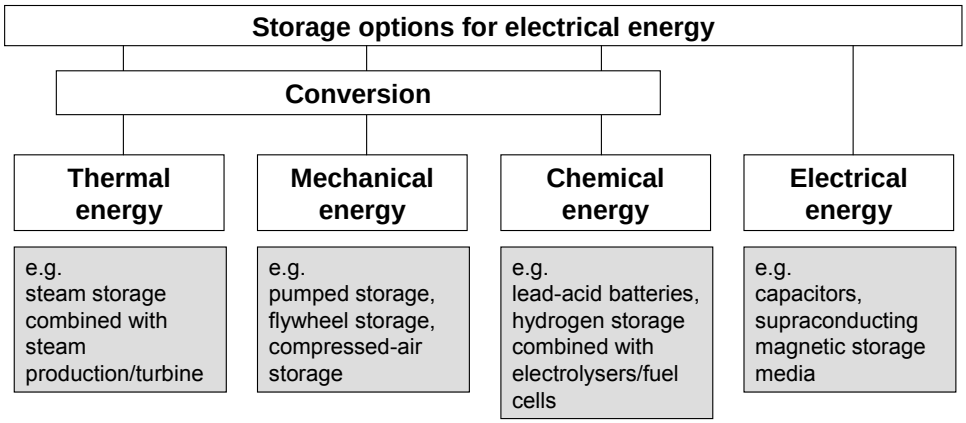


Fig. 12-1: Storage options for electrical energy [35]

Energy storage systems can be classified in terms of their electrical power, storage performance and capacity, primary areas of application (balancing of short-term power fluctuations or energy storage), efficiency (including auxiliary energy demand and standby or discharge losses), and marketability (Table 12-1)

In terms of their functionality storage systems can be divided into two classes: While electrical and flywheel storage systems are mainly suitable for balancing short-term *power* fluctuations, pumped-storage hydropower plants and compressed-air storage systems are used for balancing fluctuations over longer periods (hours or days).

Pumped-storage hydropower plants offer the highest energy storage performance and capacity. In pumped-storage hydropower plants a pumping turbine pumps water from a reservoir into a second reservoir at a higher level. In generator mode the potential energy stored in the water is converted back into electrical energy. The efficiency of this charge/discharge cycle is between 65 and 85% (typically 75%). Pumped-storage hydropower plants are characterised by fast response times. After only about two minutes from standstill they can feed into the grid with their rated output and are therefore particularly suitable for peak load and instant backup. These power plants are usually designed to provide electricity for four to ten hours under full load. Pumped-storage hydropower plants often also have natural tributaries. However, as a long-term average figure for all German pumped-storage hydropower plants, around 75% of the total electricity supplied can be attributed to pumped mode [36].

In Germany 30 pumped-storage hydropower plants with electrical capacities between 3.3 MW and 1,060 MW are in operation. The total capacity is around 6.7 GW_{el}.

In addition to above-ground pumped-storage hydropower plants there is also potential for underground pumped-storage hydropower plants, e.g. in former ore mines. Such pumped-storage power plants have considerable advantages from a nature and landscape conservation perspective, because the required gradient does not have to be created through artificial landscape intervention. Existing underground voids can be used instead. Plans for the construction of a first underground pumped-storage hydropower plant with a rated capacity of up to 2,000 MW in a former ore mine in New Jersey, USA, are currently being considered by the relevant planning authorities.

Research, development and demonstration projects associated with this technology should be supported, the usable potential explored and geological effects examined.

In addition to pumped-storage hydropower plants, compressed air energy storage (CAES) systems are also suitable for storing large quantities of energy. In a CAES system electrical energy is converted to pressure energy with the aid of a compressor and stored in underground salt caverns. For re-conversion to electricity the compressed air flows through a turbine that generates electricity in conjunction with a generator. CAES plants are characterised by good part-load behaviour and a high degree of flexibility for power generation.

One of the world's two CAES plants operates in Germany. It was built in conjunction with the Unterweser nuclear power plant in order to store electricity during low-tariff times and at the same time to secure the emergency power supply and black starting capability of the plant. Air is stored in two salt caverns with a total volume of more than 310,000 m^3 at a pressure between 50 and 70 bar. The plant is located at Huntorf and has a capacity of 290 MW. It features supplementary natural gas firing for heating the air prior to expansion in the gas turbine. Without this the air would freeze during expansion and damage the turbine. The efficiency is therefore comparatively low. To provide one part of electricity 0.9 parts electrical work and 1.6 parts natural gas are required. This corresponds to a calculated efficiency of around 40%, with one third of the energy input supplied in the form of electrical work. In addition to the Huntorf plant a second plant with a capacity of 110 MW exists in McIntosh, Alabama, which benefits from technological optimisation measures leading to significantly higher electrical efficiency (54%). Further plants are currently at the planning stage, including a 2.7 GW power plant in Norton, Ohio. A starting point for increasing the efficiency is a recuperator that utilises the flue gases from the gas turbine and if appropriate the compressor heat for preheating the air.

An adiabatic compressed-air energy storage plant (AA-CAES) represents a further development. In this power plant type a heat store stores the heat released during air compression and releases it to the air during discharge. No supplementary fossil firing is required. The aim is to achieve charge/discharge efficiencies of 65 to 70%. However, these efficiencies do not take into account startup losses that occur due to the fact that the compressor can only feed in compressed air once the required cavern pressure has been reached. Depending on the cycle frequency this may reduce the efficiency significantly.

To date no such AA-CAES power plant has been built. A research consortium examined various plant configurations as part of an EU project. Challenges include choosing a suitable thermal storage material and adaptation of the compressor train and the air turbine. The first AA-CAES demonstration applications are expected at the start of the next decade, although large-scale availability is not expected until around 2020.

In addition to power plants that are suitable for storing large quantities of energy there is a wide range of technologies that can be used as reserve capacity.

Flywheel storage systems that convert electrical energy into rotational energy can have a capacity of up to 3 MW. Since flywheel storage systems can only supply power for a few seconds or minutes they are mainly suitable for stabilisation of power grids and ensuring voltage and frequency stability.

Chemical storage batteries can, in principle, be installed with any capacity, although in practice their operational capability is limited by their space requirements and investment costs. Storage batteries are mainly used in decentralised systems. In addition to lead-acid batteries new battery technologies such as nickel metal hydride and lithium ion systems are increasingly being used. [37]. Redox flow batteries are reversible fuel cells with separate electrolyte storage tanks. They are currently at the pilot and demonstration stage. According to the European "SmartGrids" technology platform, batteries installed in electric cars and plug-in hybrid vehicles may become increasingly significant in future.

Superconducting magnetic energy storage systems (SMES), which store electricity in the magnetic field of a superconducting coil, are mainly used as small storage devices for ensuring voltage and frequency stability. Only few companies are currently involved with commercial development of SMES. Capacitors also discharge their energy within a very short time (milliseconds) and are therefore not suitable for bridging low-wind periods, for example.

Finally, electric current can also be stored as compressed or liquefied hydrogen through electrolysis. The hydrogen can be re-converted to electricity in a fuel cell, which offers the highest electrical efficiencies. However, according to optimistic assumptions the efficiency of such storage systems is only round 40%. This technology may become more significant once hydrogen is used in the transport sector. While electrolysis is a long-established technique, particularly in the chemical industry (for example in fertiliser production), the combination of electrolysis, hydrogen storage and fuel cells has so far only been examined in field tests due to the prohibitively high costs and low efficiencies. One example is a project on the Norwegian island of Utsira, where two wind turbines were coupled with a flywheel and an electrolyser. The hydrogen generated by the electrolyser is stored in pressure vessels and converted back into electricity by means of a fuel cell or an internal combustion engine.

Table 12-1: Characteristics of different storage options [35, 37, 38]

		Large-scale storage systems (>10 MW)					Decentralised storage systems (kW - 10 MW)				
		Pumped storage plants	Compressed air storage		H2+Fuel cell	Large battery storage systems	Redox flow batteries	Flywheels	SMES	Capacitors	Storage batteries
			CAES	AA-CAES							
Technical parameters											
Typical capacity in[1]		3 to 1060 MW	110 to 290 MW, in future up to	in future hundreds MW to GW	kW to GW		MW	5 kW to 3 MW	10 kW to 1 MW	<150 kW	<500 kW
Typical efficiency [2]	%	65 to 85	45 to 55	65 to 70 [4]	30 to 40	65 to 85	70	80 to 95	90 to 95	90 to 95	65 to 85
Typical standby losses		0 to 0.5 %/d	0 to 10 %/d		0 to 1 %/d	0.1 bis 0.5 %/d		3 to 20 %/h	10 to 12 %/d	0.1 to 0.4 %/h	< 0.01 %/h
Typical		Peak load/peak shaving, system services (e.g. black startup, minute reserve)			Long-term storage, off-grid applications, H2 as fuel	Long-term storage, Off-grid	Short-term storage, reserve capacity, UPS				
No. of cycles						< 1000			approx. 1,000,000	> 1,000,000	< 1000
Discharge time		4 to 10 hours	2 to 24 hours		Seconds to days	hours		Seconds to minutes	Seconds to minutes	Seconds	Minutes to hours
Market											
Specific investment costs [3]	€/kWh$_{Out}$	100 to 500	40 to 100		Not yet available		100 to 1,000	1,000 to 5,000	30,000 to 200,000	10,000 to 20,000	800 to 1,000
Ecology		Expansion environmentally				Disposal problematic, depending on battery type					
Installed capacity in D	GW	6,7	0.29	0							
Market stage		Marketab	Marketab	Research	Prototyp	Marketab	Prototype, in some cases marketable	Marketable in smaller quantities	Prototyp	Prototyp	Marketab

[1] For new technologies: expedient capacity class [2] Charge / discharge cycle [3] Based on the energy content of the storage system; lower bandwidth: Reduction
[4] Without consideration of startup losses d: Day UPS: uninterruptible power supply

12.2 Application of electricity storage systems in the energy sector

Energy storage systems are already being used for various purposes in the energy sector. Pumped-storage hydropower plants are used as large-scale storage systems for covering load peaks and unexpected fluctuations in electricity consumption and supply (e.g. failure of other power plants). Operators of pumped-storage power plants can trade in wholesale energy and minute reserve capacity, because they can respond flexibly and supply positive and negative balancing energy. In the event of power failures pumped-storage hydropower plants (and the CAES plant at Huntorf) enable other power plant blocks to be restarted due to their black starting capability. In addition they can provide other system services (minute reserve, reactive power, voltage and frequency stability, reduction of grid losses, emergency power). Depending on the grid infrastructure electricity storage systems can improve the utilisation of the available transport capacities, because they no longer have to be designed for load peaks. In some cases the time required for reinforcing the grid equipment or grid expansion can be bridged. This may be particularly significant in conjunction with feed-in points for fluctuating power sources (e.g. offshore wind). Similar to market-oriented redispatching, grid operators would have to arrange for electricity storage. The costs for this storage would be charged to the transmission grid operator who would apportion them to the grid fees.

Through better uniformity of power generation future (conventional) new power plants may be designed smaller and simpler, since control capability may not be required. While energy storage is associated with efficiencies of significantly less than 100% due to charge/discharge losses and standby losses during storage, it can nevertheless save fuel in conjunction with fluctuating supply systems, because the number of conventional power plants operated in partial load mode (associated with lower efficiency) is decreasing, and in addition the number of situations in which feed-in from wind energy systems due to potential grid overload has to be limited (generation management), could be reduced significantly. However, for power plants offering greater flexibility this effect is much less pronounced.

In addition, electricity storage systems can contribute to improved supply quality through uninterruptible power supply (UPS) or stabilisation of power grids.

12.3 Direct coupling of energy storage systems with renewables

Beyond routine operation of large storage systems there are a number of pilot and field trial projects in which energy storage systems are linked with renewable power installations to form hybrid systems.

In state-of-the-art installations battery systems are coupled with various renewable energy technologies (and in some cases diesel generators) in off-grid systems and other decentralised applications. In some larger projects batteries and redox flow batteries have been coupled with PV or wind power systems (Herne, Bocholt: 1.6 MW lead-acid batteries, Japan: coupling of 4 MW/6 MWh flow batteries with a 30 MW wind farm, coupling of a 500 kW wind turbine with a 400 kW battery system).

In some applications storage systems are linked directly with renewables for reasons of voltage quality. One example is a 200 kW flywheel (storage capacity 5 kWh) coupled with a wind energy system from Enercon.

To date coupling of wind farms with large energy storage systems has only been examined as part of planning or research projects. In Iowa, for example, a 75 to 150 MW wind farm in

combination with a CAES plant has been proposed [39]. European projects are exploring the combination of wind farms with hydrogen production (e.g. HyWindBalance, Utsira).

Such projects involving system-specific energy storage promote the technological advancement of storage systems. In the German energy sector they are initially of interest in special and niche applications (e.g. off-grid and remote systems). This is due to the fact that overall the German balancing energy market works well, and cost-efficient requisition of positive and negative reserve capacity takes places via price signals. With increasing proportions of fluctuating supply the significance of renewables for the provision of balancing energy and system services is increasing.

12.4 Economics of storage systems

The cost-effectiveness of different storage options strongly depends on the capital costs of the respective technologies. The specific investment costs (per kW of capacity) vary substantially between around 100 €/kW for high-performance capacitors and up to 10,000 €/kW for flywheels. Based on a storage capacity of 1 kilowatt-hour of electricity, and taking into account the efficiency of the charge/discharge cycle, the investment costs for storage technologies also vary significantly. Efficiency is an important input variable.

Pumped storage systems have investment costs of 600 €/kW if associated water storage systems are already in existence. Depending on geological circumstances investment costs may rise up to 2,000 €/kW, with strong dependence on the scope of the required construction measures.

The investment costs for CAES plants are difficult to estimate because only a few plants have been realised to date. [40] assumes investment costs of around 700 €/kW of generator output, in [41] 500 to 1,000 €/kW are quoted. Estimates for AA-CAES state specific investment costs between 850 and 1,200 €/kW [42, 43]. The cost component of cavern construction is comparatively low with less than 20% [44].

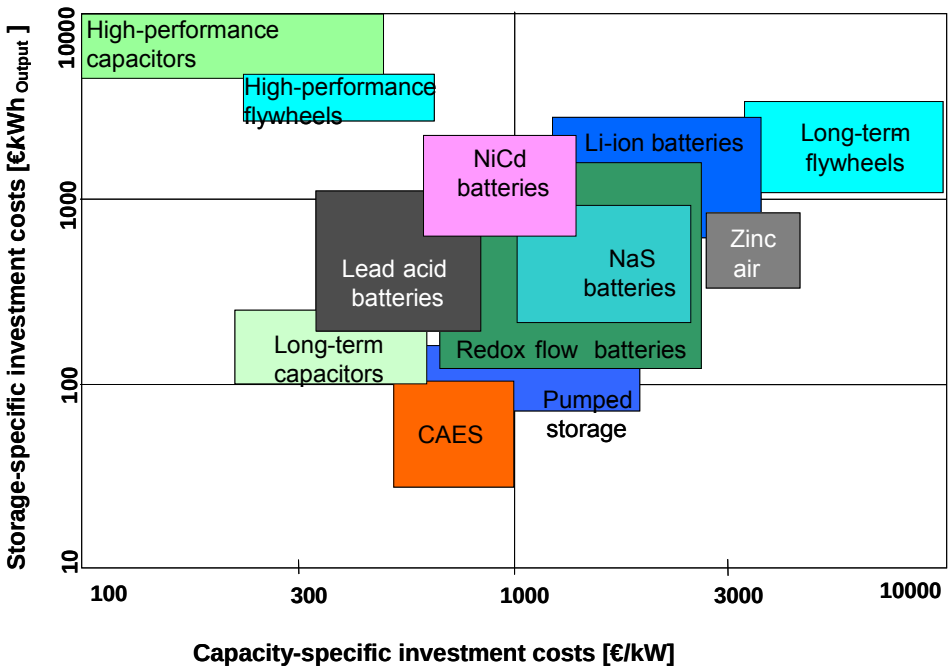


Fig. 12-2: Classification of operating and investment costs for different storage technologies (current level and short-term reduction potential) [41, 45]

12.5 Economics within the German energy system

Pumped-storage hydropower plants as large-scale storage systems and short-term storage options for certain applications are already cost-effective today. The following section discusses the cost-effectiveness of large *energy* storage systems.

In addition to the investment costs for storage technologies, the economic attractiveness is also influenced by the efficiencies of the charge/discharge cycle, the annual number of cycles, storage losses and other variable costs.

The cost-effectiveness of pumped-storage hydropower plants and future CAES plants depends on a range of factors in addition to the economic value of the system services (black starting capability, balancing energy, etc.):

- A *heterogeneous merit order* (attractive base load, expensive peak load) is advantageous in terms of cost-effectiveness.
- *Development of fuel prices* for base load and peak load electricity; above-average increases in gas prices compared with coal, for example, will have a stronger effect on peak load prices than on base load prices. The price differential is more important than the absolute level [46].
- *The flexibility of the conventional distribution system* determines whether the conventional generation mix can balance fluctuating supplies at acceptable costs. A crucial factor is the proportion of more flexible power plant technologies with low part-load losses (e.g. gas turbines) – the more flexible the generation mix, the lower the added value of storage technologies − and the installed capacity of storage systems – the higher the installed storage capacity, the lower the specific benefit of the storage systems [47].
- The proportion of more flexible power plant technologies is also significantly influenced by the *development of certificate prices and the fuel-specific configuration* [48]; with increasing certificate prices the generation mix will shift towards lower-CO_2 fuels, mainly gas; gas-based power plants can respond more flexibly, reducing the need for storage.
- *European infrastructure plans*: Expansion of transnational interconnectors leads to increasing capacities for international load balancing and storage of German electricity in Austrian or Scandinavian pumped-storage power plants, for example, and associated reduction in the volatility of electricity prices. This could also be supported through the development of a European, cross-border offshore grid in the North Sea, for example.
- *Proportion of wind energy:* With increasing wind proportion the volatility of electricity prices and therefore the attractiveness of electricity storage increases through the merit order effect. Demand for minute reserve also increases. Storage systems installed near the coast may be able to bridge the time lag until the grid infrastructure has been expanded.
- A high proportion *of heat-led CHP* supply and other *must-run* plants reduces off-peak electricity prices and therefore increases the off-peak/peak price differential.

Due to the limited scope for expansion of pumped storage facilities, further expansion of electricity storage capacity will have to focus on CAES plants. The only realised CAES plant in Germany has been depreciated and is able to offer minute reserve capacity due to the attractive prices on the German balancing energy market and can therefore be operated very cost-effectively. No new CAES power plants are currently under construction. Under current conditions expansion of CAES is not cost-effective. In addition, the German

minute reserve market is characterised by a comparatively high price levels. Plans for future CAES plans should take into account the possibility of falling prices. Current CAES plans therefore focus on the innovation effect of the associated projects, rather than short-term cost-effectiveness.

In the long term new storage power plants may become more attractive, once AA-CAES technologies have reached marketability. Simulations of the electricity market, for example in [43], that map the stochastic component of the power supply and – based on minimisation of system costs – calculate investment decisions, come to the conclusion that investments in more flexible power plants, particularly gas power plants (turbines and CCGT) increase with increasing wind penetration. If CAES is offered as a technology option (assumption: investment costs 950 €/kW, efficiency 66%), part of the investment in gas turbines and CCGT power plants is replaced with investment in CAES [43].

While systems could operate cost-effectively in Germany in future under the boundary conditions described above, there are other countries with further, advantageous parameters for storage systems. In the Netherlands, for example, the cost-effectiveness of an adiabatic CAES analysed in [46] was particularly high, because a high CHP proportion led to low off-peak prices. Also, no pumped-storage hydropower plants are available in the Netherlands. Power plant failures are particularly noticeable due to the small power plant fleet, resulting in comparatively high price peaks and volatility.

12.6 Medium-term expansion potential for large-scale storage systems

Medium-term expansion of large energy storage systems will have to be based on pumped-storage and CAES plants, because the other technologies are either not yet marketable (hydrogen/electrolysis systems) or are not suitable for storing large energy quantities.

The potential for further expansion of pumped-storage hydropower plants is very limited due to the significant environmental interventions, the long realisation time in a rather short-term energy market, and a lack of suitable locations with adequate height difference in Germany. Current activities relating to pumped-storage hydropower plants therefore focus on refurbishment and modernisation measures, including construction of additional turbines and tubes. In Germany this applies to the current upgrading of the Waldeck II plant (additional 40 MW) and the reconstruction of the Waldeck I pit power plant (70 MW) [49]. Technological optimisation measures are implemented in Switzerland and Austria, in some cases with involvement by German energy supply companies. Particularly noteworthy are Limberg II (2*240 MW in pumped and turbine mode) and Kops II in Vorarlberg, designed mainly for the German grid (3*150 MW pumped and turbine mode, commissioning scheduled for 2008) in Austria, and Linth-Limmern (860 MW Axpo project) and Oberaar-Räterichsboden (400 MW) in Switzerland [49]. Current estimates assume that over the next 15 years around 6 GW of additional pumped storage capacity could come on stream in Switzerland alone [50].

At the same time experience in Austria, for example, where Tiroler Wasserkraft AG presented a systematic "options report" indicating possible locations for future hydroelectric plants, illustrates the vehemence of the public discussion relating to actual locations [51, 52].

In the context of utilisation of storage systems in conjunction with wind-generated electricity the spatial disparity of storage options, which for topographical reasons primarily have to be located in southern Germany and in adjoining alpine countries, and regions with high wind potential has to be taken into account, although some potential also exists in northern Germany – and therefore in areas with high wind potential – for the construction of underground pumped-storage hydropower plants. The associated potential should be examined.

CAES plants offer large scope for expansion in principle. Depending on the pressure difference the storage density is between 2 and 3 kWh/m^3 of cavern volume [53]. Cavern operators recommended cavern sizes between 500,000 and 700,000 m^3. Numerous salt caverns near the coast and offshore are suitable for CAES systems.

In the North German lowlands alone there are more than 130 structures that are suitable for cavern construction. Criteria for storage exploration include suitable depth of the salt structures, disposal options for waste brine (into the sea, in brackish water regions or disused potash/salt mines), and integration into the grid infrastructure [53]. Estimates of the storage potential of suitable formations in the North German lowlands range between 2.5 and 3.7 TWh of useful energy. This value will have to be weighted taking into account the efficiencies and startup losses. In comparison: The Goldisthal pumped-storage hydropower plant has a storage capacity of around 8.5 GWh (0.0085 TWh); daily electricity demand in Germany is around 1.6 TWh. In theory the German power demand for more than two days could therefore be stored in caverns. However, storage sites are in competition with potential deposits for captured CO_2, crude oil products, or gas.

EnBW has tangible expansion plans. In 2006 the energy supply company announced plans to build a CAES plant on the German North Sea coast by 2011.

12.7 Load management in support of system integration

Load management is defined as flexible response of the demand side to certain changes on the supply side. Such changes may be:

- Increased supply of electricity from fluctuating renewables;
- Increasing market prices leading to load reduction, or falling market prices leading to a load increase; and
- Safety-relevant signals such as changes in frequency and voltage quality that lead to load shedding or load resumption.

Load management is particularly relevant for applications with a power demand profile that is sufficiently flexible. In this way they are basically able to make a positive contribution to the operating reliability of the grid through controlled load shedding or load resumption. Three applications categories are possible:

- <u>Applications with buffer character</u>
  This category includes all applications in which a shutdown of the power supply is buffered by a storage system in the wider sense. Examples include deep-freeze and refrigeration applications (e.g. coldstores), space and process heat applications (e.g. hot water generation in hospitals), and applications with demand for pressure or kinetic energy (compressors etc.).
- <u>Applications that can be switched off</u>
  This category includes applications that can be switched off for certain periods and are not associated with increased energy demand when they are restarted, e.g. dimming of lighting, switching off escalators, etc.
- <u>Applications with temporal flexibility</u>
  This category includes many traditional residential consumers (e.g. washing machines, dryers, dishwashers), the utilisation of which is not necessarily linked to a certain time of day.

12.7.1 Benefits of load management

Load management applications can buffer short- and medium-term fluctuations of electricity supply and demand (e.g. high supply of wind power at times of low demand) by operating at full load at times of electricity oversupply and minimising their consumption at times of supply shortage.

Through increased price elasticity of the demand the required power plant capacity no longer has to be based on the annual peak load that would occur without demand-side measures. This leads to cost savings. Load management can provide positive and negative balancing power. Increased uniformity of the electricity demand also leads to efficiency gains in the conventional generation mix (avoidance of operation below rated power) and facilitates integration of fluctuating supplies.

In contrast to other storage technologies load management requires no installation of new storage facilities (e.g. caverns or water reservoirs), but only modification of the application control. Load management therefore tends to be a cost-efficient option for establishing a flexible energy storage network.

Two main mechanisms are available for targeted influencing of consumer demand:

- Load response, i.e. an agreement between suppliers and customers regarding optional shutdown of loads on demand or by means of corresponding control technologies; and
- Price response, i.e. contractual or other financial incentives for demand-side response, e.g. time-varying tariffs (time of use (depending on point in time) or dynamic tariffs (coupled with stock market prices or other indices)).

Load management, particularly in the form of load response, has already been implemented with many industrial customers. In various countries, for example in individual US states (particularly California and New York), Italy or Scandinavia, extensive load management programmes are installed, including at residential customer level. In Germany there have only been few pilot projects beyond the activities at industrial and commercial customer level. Examples include the "Eckernförder Tarif" project from the 1990s and EnBW's "Preissignal an der Steckdose" project.

12.7.2 Load management potential

Prerequisites for successful load management are suitable loads and detailed knowledge of the occurrence of these loads. Particularly suitable are large industrial consumers, for example electrolysers, electric grinders, melts, electrical heat applications, or coldstores. According to estimates reported in [54] the industrial load shift potential is around 3 GW, particularly in chlorine electrolysis, food processing industry and retail industry, metal production, and the paper industry. These sectors alone are responsible for around 10% of electricity consumption in Germany.

In principle public buildings and private household/business customers can also be integrated in a load management system. Residential applications that are suitable for load shifting include circulation pumps that switch off frequency-dependent and therefore serve as instant backup, or washing, dishwashing and electric heating (hot water or heat pump). A prerequisite for participation of private households is installation of control devices in the respective households or devices. The potential for private households is estimated at around 2 GW in [55]. Another study determined the overall disposable load as around 70 Watts per household (refrigeration appliances) and the additional disposable load within a time window between 9am and 9pm as 190 to 270 Watts [40]. In principle it should even be possible to control refrigeration appliances autonomously without adaptation of user behaviour.

While load management is technically feasible and cost-effective in the industrial sector, as indicated by the first commercial examples, in the private customer segment there is a lack of appropriate business models, cost-effectiveness estimations under current information and communication systems, and provision of cost-effective, standardised communication technology and associated testing. Activities in other countries, for example Canada, Norway and Italy, indicate that load management in private households is becoming increasingly interesting. This is linked to rapid advancement of electricity metering technology (smart metering). For example, in 2006 the Italian energy supplier ENEL SpA installed more than 20 million "Advanced Metering Infrastructure" systems (developed in collaboration with IBM) for all customer classes and now offers a differentiated tariff system with discounts at certain times. At present no clear statements can be made about the costs of load management for private customers in comparison to the costs for storage technologies.

The development of intelligent application devices that automatically respond to tariff signals and feature communication interfaces is beneficial for the shift potential offered by load management. Consumer acceptance of shutdowns is a prerequisite for opening up the load management potential, at least for private households. In the past electricity has attracted little interest as a product in this sector, not least due to the fact that electricity costs only represent a small proportion of monthly outlays. In future controllable loads such as electric cars and plug-in hybrid vehicles (which are also examined for their potential as standby capacity as part of the "vehicle to grid" development) and electric heat pumps could lead to an expansion of load management potential. The same applies to controllable, decentralised generation systems such as CHP plants.

12.8 Virtual power plant as system integrator for decentralised supply systems, load management and storage technologies

Pooling of decentralised generation, load management and storage enables decentralised players to take part in the activities of the electricity market by offering balancing energy or trading on the energy exchange, for example. The key element is the communication networking of these systems. The "virtual power plant" is based on this approach. It links a wide range of small generation, loads and storage systems through ISDN data cables, or through GPRS, mobile communication or powerline, so that the systems can operated as a single power plant. The power plant is referred to as virtual – "to be in effect, but not in appearance" – because there is no single locally identifiable power plant unit; it does indeed generate power, however. The centre point of the virtual power plant is a control unit that processes the data from the decentralised generating units and compares them with forecasts for power demand, generation, and weather, queries the current European Energy Exchange conditions, and optimises overall power plant operations.

Various projects are currently implementing different virtual power plant aspects. One example is the recently completed EU project entitled Virtual Fuel Cell Power Plant.

Stadtwerke Unna GmbH are among the first suppliers using such a system. They link five cogeneration plants, two wind farms, a photovoltaic system, and a hydroelectric plant to form a single system. Steag Saar Energie AG has linked decentralised power plants and industrial loads (including steel companies, aluminium plants, chlorine industry) to form a virtual load plant ensemble. Virtual power plant concepts have also been realised as part of the Dispower project in Konwerl and at Hamburg University of Applied Sciences.

Due to the required hardware and transaction costs virtual power plant concepts lead to additional costs that have to be financed through cost reduction (e.g. quantity discount for fuel purchases, standardisation of installations) and increased sales revenues (new marketing opportunities (balancing energy, spot market) or direct supply of consumers). For decentralised CHP plants integrated into a virtual power plant the available disposable power is limited by the heat demand.

12.9 Market integration of renewables installations through direct marketing

The EEG does not prevent direct marketing of electricity from renewable energy plants, for example on the European Energy Exchange or the balancing energy market. To date modified behaviour patterns have only been observed for a few plant operators and only in situations with above-average European Energy Exchange prices. It can be assumed that the frequency and scope of these occurrences will increase with increasing Energy Exchange prices and decreasing EEG remuneration rates. Initial company consortia indicate increasing interest in the market.

This temporary opt-out from EEG-based remuneration occurs if market prices are above the level of the EEG rate. The current legal framework allows short-term deviations over short periods (15-minute interval).

The main motivations for enabling direct marketing can be summarised as follows:

- Producers of electricity from renewables can gather market experience. This includes the fact that they establish cooperation with other players in the energy market, thus creating innovative interactions between players. The latter may be particularly relevant for the time after support through the EEG for a specific plant.
- EEG fee payments and the EEG surcharge decrease nominally. (This reduction does not apply to the differential costs, but only to fee payments, see below).

Under the current EEG arrangements, these positive motivations for direct marketing of EEG electricity are counteracted by the following disadvantages:

- The incentive efficiency of the EEG decreases, since risks are socialised and opportunities are privatised. The differential costs of the EEG increase, since at times of "temporary opt-out" electricity prices are above EEG fees. If electricity is remunerated according to EEG rates during these times, it is fed into the grid at a lower rate than through sales on the European Energy Exchange, which is cheaper for the consumer and is associated with negative differential costs. In the current differential cost calculation these phases of negative differential costs are implicitly taken into account through the underlying average electricity price. Removing these phases from the overall calculation results in increasing differential costs. This effect is also referred to as "cherry picking". This term indicates the potential public perception of this approach and could result in a significant social acceptance obstacle for the EEG.
- EEG supplies (including base load) become more difficult to forecast from a transmission grid operator perspective due to short-term and severely restricted direct marketing. This leads to increasing system services costs for transmission grid operators and volume risks for the suppliers.

- The current practice of temporary opt-out leads to problems with data logging, which should at least be resolved through statistical logging of the associated electricity quantities. This increases the administrative effort associated with the EEG.

In weighing up the advantages and disadvantages of the current direct marketing provisions a fundamental revision of these provisions is suggested. Revised provisions should retain the potential benefits of direct marketing while significantly reducing the disadvantages described above. To facilitate forecastability of EEG supplies for transmission grid operators and to reduce the additional volume risks for the suppliers it seems necessary to

- announce potential opt-out from EEG remuneration with adequate lead time, and
- maintain potential opt-out from EEG remuneration over adequately long periods without interruption.

The structure of the basic conditions for temporary opt-out from EEG remuneration decides whether such opt-out is feasible in practice or not. The Federal Environment Ministry is currently undertaking research into these aspects.

12.10 Policy recommendations

Operators of electricity generating plants based on renewables currently receive no incentives through the EEG to invest in storage technologies or load management, since according to the EEG they are entitled to fixed remuneration without taking into account electricity quality or continuity of supply. The EEG offers no incentives for electricity consumers or grid operators to initiate load management or storage measures for balancing fluctuating supplies or to link plants in order to realise optimised operating strategies (combination with other renewables/combination with well-controllable power plants).

Until spring 2008 the Federal Environment Ministry will examine suitable options for an incentive system within or outside the EEG that will lead to improved overall system integration through demand-based supply or greater continuity (particularly through application of storage technologies, through networking of renewables and other decentralised plants to form "virtual power plants", and through corresponding application of load management). This could be accompanied by flanking measures in the form of research, development and demonstration projects relating to storage technologies, particularly compressed-air storage, underground pumped-storage hydropower plants, hydrogen storage, storage batteries, and load management.

In addition to greater continuity of power supply from RE plants these plants can also actively participate in the provision of system services. This question currently primarily arises for wind energy plants due to their high contribution to electricity generation and the fluctuating nature of their input. Inclusion of other sectors in these provisions at this point in time appears both unnecessary and premature.

In order to increase the marketability of power supply from renewables through the EEG and to make it more demand-oriented, a framework for temporary deviation from EEG remuneration at the request of plant operators should be created with a view to enabling direct marketing of EEG electricity on a temporary basis.

Policy recommendations regarding promotion of storage technologies and system integration

Provisions within or outside the scope of the EEG

- Incentives for improved system integration of renewables through demand-based, dynamic supply and greater continuity of the supply (specifically application of storage technologies, networking of RE plants to form "virtual power plants", and load management). Assess to what extent powers to issue statutory instruments under the EEG might be expedient. The Federal Environment Ministry should identify options by spring 2008.

Provisions within the scope of the EEG

- Provision of a framework for temporary opt-out from EEG-based remuneration at the request of plant operator with a view to enabling direct marketing of EEG electricity on a temporary basis.

Flanking measures outside the scope of the EEG

- Enhanced support for research, development and demonstration projects relating to storage technologies, particularly compressed-air storage systems, underground pumped-storage hydropower plants, hydrogen storage, and battery storage systems.
- Support for demonstration projects and market introduction of storage technologies, where appropriate.

13 Special Equalisation Scheme (Article 16 EEG)

13.1 Purpose, operation and development

In order to prevent the rapid expansion of renewable energies causing inappropriate pressures to be placed upon particularly electricity-intensive manufacturing enterprises, notably in international competition, a "Special equalisation scheme" was taken up in the EEG on 16.7.2003 as Article 11a (EEG 2003). This scheme largely relieves certain enterprises defined specifically in the Act (see below) from the obligation to purchase electricity generated within the scope of the EEG and thus relieves them of the corresponding EEG surcharge.

Upon application of the enterprises, a limit to deliveries of electricity generated within the scope of the EEG is set by means of notices issued by the Federal Office of Economics and Export Control (*Bundesamt für Wirtschaft und Ausfuhrkontrolle* – BAFA). The BAFA has been commissioned by the legislator to implement the special equalisation scheme, under the supervision of the Federal Environment Ministry (BMU). The Act stipulates precisely how to determine the level of the limit to be set individually for each delivery point. The calculation procedure is designed such that in the regular case it ensures that the EEG-related electricity price increase does not exceed 0.05 cents/kWh for the eligible enterprises.

Those eligible for making such an application pursuant to Article 11a EEG 2003 were manufacturing enterprises which, at the delivery points to be limited, purchased more than 100 GWh electricity annually at each delivery point in question. The second precondition for eligibility to make use of the special equalisation scheme was that all enterprises making an application had to furnish proof that their annual electricity purchase costs exceeded 20% of their gross value added. Moreover, they had to provide evidence in each individual case that the costs incurred by the EEG led to a substantial impairment of their competitiveness. In all cases, those eligible under Article 11a EEG (2003) had to bear a deductible share, i.e. the full EEG rate had to be paid for electricity purchased up to 100 GWh; only from then onwards did the limit come into effect.

The amended EEG which entered into force on 1 August 2004 restructured the special equalisation scheme and reworded it in Article 16 EEG (EEG 2004). For one thing, the group of eligible enterprises was expanded substantially by reducing the threshold values: From then onwards, enterprises or independently operating parts of enterprises in the manufacturing sector could already make use of the limit if they could furnish proof of an annual electricity purchase exceeding 10 GWh at the delivery point to be limited. Furthermore, the documented ratio of the enterprise's electricity costs to its gross value added now only had to exceed 15%. The individual proof of impairment of competitiveness, which until then had to be furnished at considerable expense, was no longer needed. Finally, all enterprises meeting the stricter standards of Article 11a EEG (2003) (see above) were now completely exempted from the deductible share to be borne at delivery points where consumption exceeded 100 GWh. For the enterprises newly becoming eligible for the scheme, the limit to electricity generated within the scope of the EEG was set at a deductible share of 10% of their electricity consumption in the last closed financial year.

Moreover, the EEG 2004 broadens the scope of those eligible for participation in the special equalisation scheme to include railway operators. The limiting parameter of the ratio of the company's electricity costs to its gross value added did not apply to them. However, a deductible share of 10% was set for railway operators, regardless of their annual total electricity purchase.

To offset the substantial expansion of the scheme, Article 16 contained two provisions designed to prevent excessive burdens upon non-privileged electricity users. Under these provisions, the EEG-related costs aggregated across all non-privileged electricity users were not allowed to rise by more than 10% ("10% aggregate cap"). Moreover, within this 10% cap the volume of relief for companies operating railways was limited to a maximum of 20 million euros ("rail cap").

In the notice-issuance process for 2005, which was under way in 2004, the 10% cap already came into play, with the result that the EEG differential costs of the particularly electricity-intensive enterprises, at an average of about 0.11 cents/kWh, were more than twice as high as the above-mentioned reference value of 0.05 cents/kWh. For 2006, the differential costs of the particularly electricity-intensive enterprises then doubled again to about 0.2 cents/kWh. In this situation, and in view of the – not EEG-driven – drastic electricity price increases, it was agreed in the 2005 coalition agreement to firmly limit the EEG differential costs of the electricity-intensive industries to 0.05 cents/kWh and, at the same time, to improve transparency in the calculation of the EEG surcharge in the interests of protecting the non-privileged electricity users.

These agreements were implemented in the 1st EEG Amending Act (*1. EEG Änderungsgesetz* – 1. EEG ÄG), which entered into force on 1.12.2006 (EEG 2006). In addition to provisions designed to improve the transparency of the entire EEG passthrough and billing mechanism, that act abolished without substitute the two above-mentioned cap systems. The latter change applied retroactively from 1.1.2006. It was implemented by the BAFA immediately after entry into force of the Act by means of 442 amendment notices. The enterprises privileged in 2006 according to Article 16 EEG (2006) are consequently entitled to a further relief.

Table 13-1 summarises the main development phases of the special equalisation scheme.

Table 13-1: Development of the special equalisation scheme under the EEG since 2003 [6, 56, 57]

	EEG of 16 July 2003, Art. 11a	EEG of 21 July 2004, Art. 16	EEG Amending Act of 7.11. 2006, Art. 16
Preconditions for eligibility	• Manufacturing enterprises with a ratio of their electricity costs to their gross value added > 20% and an electricity consumption > 100 GWh/a at delivery point • Only concerns electricity purchased from the public grid • Documentation of impairment of competitiveness required in each individual case	• Manufacturing enterprises with a ratio of their electricity costs to their gross value added > 15% and an electricity consumption > 10 GWh at delivery point, and also railway operators (electricity cost share >10 GW) • Only concerns electricity purchased from the public grid • Individual documentation of impairment of competitiveness no longer required	No change
Relief for privileged electricity consumers / protective rules for non-privileged consumers	• Limitation of obligation to purchase electricity generated within the scope of the EEG, with the goal of limiting the EEG surcharge to 0.05 cents/kWh • Rule only comes into play if consumption is greater than 100 GWh; the full EEG rate applies to consumption up to that threshold • Non-privileged end consumers pay for the difference; however, the BAFA has a duty to examine case by case whether a disproportionate additional burden arises for other electricity users; because the impact of each individual case was too small, this rule never came into play	• Limitation of obligation to purchase electricity generated within the scope of the EEG, with the goal of limiting the EEG surcharge to 0.05 cents/kWh • Generally 10% share to be borne; if ratio of the enterprise's electricity costs to its gross value added ≥ 20% and consumption ≥ 100 GWh then no share to be borne • Non-privileged end consumers pay for the difference, but this is limited to a maximum rise of 10% from the previous year's level (10% cap), if 10% threshold crossed • Railway operators are also eligible for relief if their individual electricity purchase exceeds 10 GWh/a; but this is limited to an aggregate maximum of 20 million euros per year (rail cap)	• Generally 10% share to be borne; if ratio of the enterprise's electricity to its gross value added ≥ 20% and consumption ≥ 100 GWh then no share to be borne • Limitation of obligation to purchase electricity under the EEG, on the principle that the surcharge is limited to 0.05 cents/kWh • Removal of the 10% cap • Removal of the rail cap

13.2 Use of the special equalisation scheme in the period from 2003 to 2007

Table 13-2 shows the use made of the special equalisation scheme since 2003. Figures until the end of 2004 have been partly aggregated because the notices issued pursuant to Article 11a EEG (2003) were each valid for one year after their entry into effect and were issued successively. Starting in 2005, notices are all issued by BAFA at the beginning of the year and apply for one calendar year.

Table 13-2: Use of the special equalisation scheme under the EEG since 2003 [1, 58, 59]

	2007	2006	2005	2004	2003 (July onwards)
Privileged enterprises; of these **railway operators**	**382** 42	**327** 45	**297** 45		**59** **-**
Privileged electricity quantity [GWh] (Source: BAFA notices) - Manufacturing enterprises - Railway operators	**72,040** 67,826 4,214	**68,680** 64,584 4,096	**59,289** 54,817 4,472		**34,407**
Actual use [GWh] (Source: VDN annual accounts)	To be presented by VDN by 30.09.2008[18]	**70,161**	**63,474**	**36,865**	**5,847**

The steep rise in the number of privileged enterprises in 2005 is due particularly to the distinct reduction in threshold values. The further rise in subsequent years is due on the one hand to the general economic upswing and rising prices on the general electricity market, as a result of which many enterprises met the eligibility criteria for the first time. A further factor is that – after only little time remained for the application procedure for 2005 following the amendment to the EEG in 2004 – in 2006 the increasing knowledge among enterprises of the scheme presumably played a role.

The “privileged electricity quantity” for which applications were made also rose in step with the number of privileged enterprises. For reasons of practicability and legal certainty, this quantity is determined in each case on the basis of the last business year of the privileged enterprise prior to application. The actual use made of the scheme within the eligible period can deviate from these figures.

Detailed analysis for the year 2007 has shown that some 20% of all privileged delivery points (103 out of 507) are located in the eastern Länder of Germany. The approved privileged end-user consumption in those Länder accounted, at about 10,400 GWh, for roughly 15% of the total volume approved.

Table 13-3 shows the sectoral distribution of enterprises privileged in 2007. This is similar to the distribution in the two previous years: The quantity of privileged electricity consumption diverges widely among the various sectors. The statement of average values tends to play down the actual divergence. For instance, the privileged individual enterprises with the highest electricity consumption in the aluminium and chemicals sectors each have electricity consumption levels of several thousand GWh/a, which places them significantly above the average levels listed.

[18] Data will be published on the BMU website when they become available.

Table 13-3: Sectoral distribution of use made of Art. 16 EEG in 2007 [1, 58]

Sector	Number of enterprises	Privileged end-user consumption [GWh/a]	Privileged end-user consumption per enterprise [GWh/a]
Manufacture of chemical products	52	20,219	389
Production / initial processing of non-ferrous metals	16	12,973	811
Paper and paperboard production	64	12,117	189
Production of basic iron and steel and of ferro-alloys	29	9,104	314
Railway operators	42	4,214	100
Production of cement	25	3,014	121
Manufacture of wood and products of wood (excluding furniture)	18	1,844	102
Basic metals	28	1,761	63
Electricity, gas, steam and hot water supply	16	934	58
Food products and beverages	34	1,040	31
Other sectors	58	4,819	83
SUM TOTAL	**382**	**72,040**	**189**

Fig. 13-1, which is based on the above data, further shows that only four sectors – iron/steel, non-ferrous metals, chemicals and paper – account for some three-quarters of the entire privileged end-user consumption and that these sectors are thus the main beneficiaries of the special equalisation scheme.

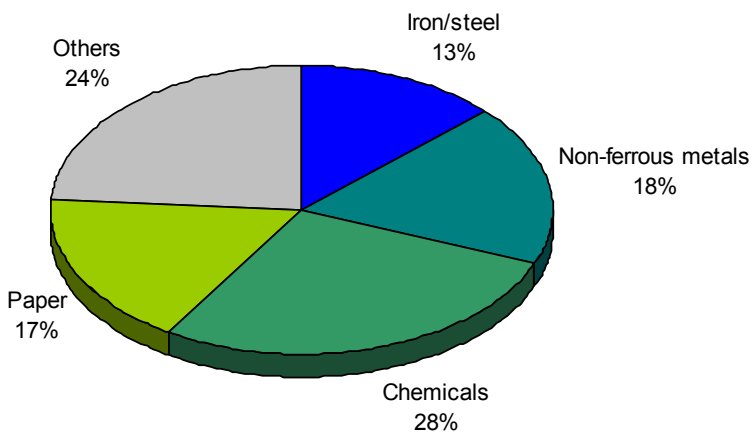


Fig. 13-1: Sector distribution of privileged end-user consumption under Art. 16 EEG in 2007 [1, 58]

13.3 Financial impacts of the scheme: An overview

A set of assumptions needs to be made in order to be able to appraise the financial impacts of the special equalisation scheme for beneficiaries and for the other, non-privileged electricity consumers. The findings summarised in Table 13-4 result from data published by the VDN and draw on scientific studies[19].

Table 13-4: Financial impacts of the special equalisation scheme since 2003 [1]

Aggregate values	**2003**	**2004**	**2005**	**2006**	**2007**
End-user consumption [TWh]	*478*	*488*	*491*	*495*	*495*
Electricity generated within the scope of the EEG [GWh]	*28,471*	*38,511*	*44,004*	*53,374*	*60,000*
Average payment under the EEG [cents/kWh]	*9.2*	*9.3*	*10.0*	*10.4*	*10.6*
Applicable value of electricity generated within the scope of the EEG [cents/kWh]	*2.4*	*2.9*	*3.7*	*4.4*	*5.0*
EEG surcharge assuming no special equalisation scheme under Art. 16 EEG [cents/kWh]	**0.40**	**0.51**	**0.56**	**0.65**	**0.68**
Privileged enterprises					
Privileged electricity quantity [GWh]; estimated for 2006/2007	*5,847*	*36,865*	*63,474*	*70,100*	*74,000*
EEG surcharge [cents/kWh]	0.05	0.05	0.11	0.05*	0.05
Savings of beneficiaries [million €] attributable to Art. 16 EEG	**20**	**170**	**290**	**420**	**460**
of this, railway operators	**-**	-	**<20**	**25**	**30**
Other, non-privileged consumption					
EEG surcharge [cents/kWh]	**0.41**	**0.54**	**0.63**	**0.75**	**0.79**
EEG costs of private household (3,500 kWh/a)[1)] [€/month]	**1.18**	**1.59**	**1.84**	**2.17***	**2.30**
of this, extra costs due to Art. 16	0.03	0.09	0.20	0.28	0.32
Example: EEG surcharge for enterprise (1 GWh/a) [€/a]	4,100	5,400	6,300	7,500	7,900
of this, extra costs due to Art. 16 EEG [€/a]	100	300	700	1,000	1,100
Explanations					

** Fictitious value assuming retroactive application of the EEG Amending Act. In actual fact, the EEG surcharge of privileged enterprises figured approx. 0.2 cents/kWh in 2006. The EEG surcharge for non-privileged consumers accordingly only figured 0.72 cents/kWh; the monthly EEG costs of the reference household figured €2.11. The savings for beneficiaries allowed for 2006 by the EEG Amending Act will be disbursed in the following years.*
1) Reference household for three persons, after VDEW 2007

In 2006, the volume of benefits provided by the special equalisation scheme in the new amended version is assumed to have figured about €420 million, which is already well over twice as much as in 2004, the first full year of application of the scheme. Taking account of the retroactive provision of the EEG Amending Act of 2006, the remaining EEG costs of privileged enterprises in 2006 only figured about €50 million.

[19] For 2006 and 2007, for instance, forecasts of Germany-wide electricity production and average payments under the EEG are needed, as the annual statements of the VDN only become available at the end of October of each subsequent year. As the limit notices do not set any absolute electricity quantities, but only assign limit factors (see above), the electricity consumption of the privileged enterprises also has to be estimated. Finally, the “applicable value” assumed for electricity generated within the scope of the EEG plays a particular role. A more detailed discussion of these aspects, together with sensitivity calculations, is to be found in the scientific background study.

Greater uncertainties still attach to estimates for 2007. It appears certain, however, that the volume of benefits provided has continued to rise: Depending upon the development of electricity quantities fed into the grid and remunerated under the EEG, this volume will have been in the order of 450 to about 520 million euros.

The monthly EEG costs of a reference household with an annual electricity consumption of 3,500 kWh/a (for three persons, after VDEW, 2007) figured about €2.20 in 2006; the special equalisation scheme accounted for just under 30 cents out of that figure, i.e. a proportion of about 13%. This proportion can be expected to have remained at about the same level in 2007. A non-privileged enterprise with an annual electricity consumption of 1 GWh presently incurs extra costs of about €1,000 per year attributable to Art. 16 EEG. Assuming an average electricity price of 12 cents/kWh (without value-added tax) that figure corresponds to less than one percent of that enterprise's annual electricity costs.

Table 13-5 provides a representative calculation for 2006 showing how the extra costs generated by Art. 16 EEG are roughly apportioned to individual groups of non-privileged electricity consumers. The table also documents the impacts of the 2006 EEG Amending Act as compared to the provisions previously in force.

Table 13-5: Distribution of extra costs generated by Art. 16 EEG among individual groups of non-privileged electricity consumers in 2006 [1]

Sector	Electricity consumption (proportion of end-user consumption according to VDN; estimated)	EEG costs (assuming no special equalisation scheme) [million €]	EEG costs under Art. 16 before amendment (with cap) [million €]	EEG costs under EEG Amending Act (without cap) [million €]
Industry	42%	1,350	1,160 (- 190)	1,100 (-250)
- privileged	*13.5%*	*440*	*140 (-300)*	*50 (-390)*
- non-privileged	*28.5%*	*910*	*1,020 (+110)*	*1,050 (+140)*
Transport	3%	100	90 (-10)	90 (-10)
- privileged	*1%*	*30*	*10 (-20)*	*5 (-25)*
- non-privileged	*2%*	*70*	*80 (+10)*	*85 (+15)*
Residential	28%	890	990 (+100)	1,020 (+130)
Others (commercial/trade/ services, agriculture, public institutions)	27%	860	960 (+100)	990 (+130)

The figures show that, following entry into force of the EEG Amending Act, the non-privileged industrial electricity consumers bear around 140 million euros – which is about one-third – of the extra costs generated by Art. 16 EEG. The net benefit to industry is accordingly reduced to a total of around 250 million euros.

When interpreting the above representative calculations one important aspect needs to be kept in mind: All examples proceed from the – implicit – assumption that the benefits or extra costs arising due to Art. 16 EEG are passed through to all market players completely evenly by the utilities. This, however, is not necessarily the case in reality. Depending upon market situation and behaviour, the degree to which benefits and costs are passed through to privileged and non-privileged electricity consumers can differ widely. The impact mechanisms and cost parameters reported here are therefore far more robust for macro-economic assessments than for micro-economic analyses.

13.4 Evaluation of impacts

The sectors benefiting particularly from Art. 16 EEG (chemicals, aluminium, other primary production and processing of non-ferrous metals, paper and paperboard production, steel production) are strongly oriented to exports and have succeeded in raising their export share in recent years. This would suggest the conclusion that the special equalisation scheme has succeeded in meeting its principal purpose, but this cannot be verified in detail. Sufficiently precise company-level or sector-level data on this point are not available, nor could they be gathered in the course of the scientific studies feeding into the EEG Progress Report. Moreover, the enterprises benefiting from Art. 16 EEG are under no obligation to provide information on these matters.

If the 2006 EEG Amending Act had not entered into force, the special rail cap would have come into play for the first time in 2007. Fundamental transport and environmental policy considerations were the reason why this sector was included in the special equalisation scheme in 2004 and continued to be among its beneficiaries under the 2006 EEG Amending Act. This is also the reason why railway operators need not furnish evidence of a particularly high ratio of their electricity costs to their gross value added. The privileged electricity quantity in the railway sector remained roughly constant in the past year. No major changes are anticipated here in future.

The manufacturing enterprises falling under the deductible share rule and all beneficiary railway operators must currently bear average EEG-induced extra costs of about 0.11 cents/kWh, i.e. just under one-seventh of the costs incurred by non-privileged electricity consumers. Following entry into force of the 2006 EEG Amending Act, the reference value of 0.05 cents/kWh applies to particularly electricity-intensive enterprises.

At both margins of the group of manufacturing enterprises falling under the deductible share rule (electricity consumption between 10 and 100 GWh/a at delivery point and/or ratio of electricity costs to gross value added between 10 and 15%) step effects naturally occur under the current provisions. Specifically, the EEG costs of an enterprise with an electricity consumption of just under 100 GWh at a certain delivery point, all other parameters being equal, can theoretically be in the order of 50,000 €/a higher at present than the costs of the first beneficiary only just exempted from the deductible share. However, there are no indications that applicants exploit this threshold systematically. An initial evaluation of applications for 2006 and 2007 has shown that the above situation only arises in very few cases for enterprises of the same sector. In view of electricity costs which, in the case under consideration here, amount to very roughly 5 million €/a, even in such cases no substantial distortion of competition arises.

At the present time, no targeted and administrable ways of improving this situation have yet been identified. The question of how this issue can be addressed appropriately is currently under examination. That process will need to take account of the experience gathered in the first years following entry into force of the 2006 EEG Amending Act.

In extreme cases, cost disparities of a scale similar to that set out above can also arise between the last enterprise not yet falling within the scope of Art. 16 EEG (2006) (10 GWh/a electricity consumption) and the first beneficiary. In view of the lower absolute electricity costs in such a case, the relative impacts would be greater. No robust data on this issue is yet available.

A special situation arose in a small number of cases for newly established enterprises. Under Art. 16 para 2 EEG (2006), the parameters of relevance to the decision-making procedure must generally be documented by figures for the last closed financial year that have been certified by a chartered accountant. This reference to unequivocally verifiable past data had been desired at the time by industry for reasons of practicability; it is also required as a

matter of legal principle in view of the burdens to third parties that result from the benefits provided. Consequently an application made in 2005 for the 2006 approval period was based on data taken from the last financial statement completed prior to that application (generally that of 2004). This puts newly established enterprises that do not yet have a financial statement at a disadvantage. Acting in consultation with the BMU, the BAFA has always accepted an interim financial statement in such cases and has granted benefits, as long as the relevant threshold values are reached by current data. Two larger newly established enterprises have profited from this. As, for the above reasons, targeted figures or comparisons with reference enterprises cannot be accepted, a systemic disadvantage for smaller new enterprises in particular does remain despite the pragmatic approach taken by the BAFA.

Practical implementation of the scheme by BAFA has been largely unproblematic. Since 2004 the decisions applicable for one calendar year have been sent out on schedule to the end of the year. Thanks to an extremely service-focussed and professional implementation, the number of rejections and objections has been smaller than might have been expected in view of the complex subject matter and the exceedingly tight application schedule in 2004. Table 13-6 illustrates this.

Table 13-6: Rejections and objections relating to Art. 16 EEG by the BAFA [1]

Application procedures for the year	Number of applications (in some cases for several delivery points)	Rejections of applications in their entirety	Partial rejections for individual delivery points, with positive overall decision	Objections (including objections to positive decisions on grounds of inappropriate calculation)
2005	360	40	12	56
2006	367	15	8	28
2007	406	14	10	14

One of the main reasons for rejections was failure to cross the prescribed threshold values. In some cases, even parameters certified by chartered accountants did not stand up to scrutiny. Another reason for rejection was failure of applications to meet deadlines. This concerned both the documents to be furnished by the applicants themselves, and also, in some cases, the corresponding utility certificates. Most of the objections to decisions taken for the year 2005 were concerned in a non-specific manner with the first application of the 10% cap, whose calculation procedure was uncomprehensible to many enterprises. Only in very few cases, however, have objection proceedings continued to be pursued.

13.5 Policy recommendations

In view of the recent adjustment of the special equalisation scheme (with entry into force of the 1st EEG Amending Act on 1.12.2006) this report recommends abstaining from further fundamental changes to the scheme and initially monitoring further developments. This applies both to possible changes to the threshold values including the parameters to be taken into account, and the rules governing deductible shares. A further expansion of the aggregate volume of benefits granted does not appear acceptable in the light of the associated reciprocal additional burdens placed upon all non-privileged electricity consumers. Nor does any such expansion appear called for in the light of the experience gathered to date. Conversely, adjustments leading to reduced benefits for a part of the enterprises that have been privileged until now – which would thus open up scope for redistribution – would at the present time run counter to the intention of the EEG Amending Act of giving beneficiaries longer-term certainty with regard to their EEG costs.

Not least, it also appears expedient to retain the past procedure in view of the administration of the special equalisation scheme. After a period of initial and in some cases substantial problems among applicants, both the beneficiary enterprises and the BAFA are now well acquainted with the application procedure. Changes to the basic structure of the scheme would generate renewed uncertainty.

Nonetheless, while retaining the basic architecture of the special equalisation scheme some concrete proposals do result that could improve the administration of the application and calculation procedure for applicants and implementing authorities alike.

For one thing, introducing a second application deadline for newly established enterprises appears purposeful. Such enterprises should be permitted in future – in narrowly defined cases – to submit their applications by 30 September, i.e. after the general deadline of 30 June, which would continue to apply to all others. This would make it easier for newly established enterprises to use actual data from a short business year to furnish evidence that they have attained the threshold values of Art. 16 EEG, and to enjoy the benefits without delay.

In view of the reluctance of enterprises privileged under Art. 16 EEG to divulge information when surveyed in the course of compiling the present EEG Progress Report, it would be expedient to stipulate in future a duty to provide information on the experience and impacts associated with the equalisation scheme. When preparing the present Progress Report, the lack of such a provision has greatly hampered the formulation of robust statements on the micro-economic effectiveness and appropriateness of the scheme. Steps need to be taken to ensure that this does not recur in future reviews of the EEG. That process must strictly protect the business secrets of the enterprises surveyed.

Applicants must currently furnish proof of their specific electricity quantities and costs by submitting a certificate by a chartered accountant together with their application. It would greatly facilitate the administrative procedure if the utility certificate which until now had to be produced by an applicant were no longer a required part of the application procedure. Instead of basing its decision on individual, utility-specific differential costs as is presently the case, the BAFA could take recourse to a uniform reference value which would then need to be regulated in the EEG.

Policy recommendations for the special equalisation scheme (Article 16 EEG)

Provisions within the EEG

- Introduction of a second application deadline for newly established enterprises in narrowly defined cases.
- Introduction of a duty for privileged enterprises to disclose information when preparing the EEG Progress Report, whereby the process must strictly protect the business secrets of the enterprises surveyed.
- Simplification of the calculation procedure by taking recourse to a uniform differential cost reference value; this would involve removing the duty to produce enterprise-specific values by means of utility certificates.

14 Prospects for Renewable-Generated Electricity

This chapter looks at the prospects for renewable-generated electricity to 2020 and beyond. Whereas the previous chapters of this report have reviewed past trends, in this chapter, it is necessary to turn to scenario planning methodology. Scenarios do not claim to be forecasts which anticipate the future. Rather, they are based on "if – then" observations, i.e. on various plausible assumptions and scientifically established facts which can be used to develop appropriate models whose results can be assessed along a timeline.

This chapter will refer specifically to the Lead Study 2007 [5] commissioned by the BMU, which was used to develop scenarios for the Energy Summit [60]. The Lead Study takes up the long-term objectives established in the Federal Government's Sustainability Strategy, which include the target of cutting Germany's CO_2 emissions by around 80% by 2050 compared with the 1990 baseline while meeting around half Germany's energy requirement from renewables.

14.1 Development of renewable-generated electricity by sector, Lead Study 2007

For the electricity sector, the Lead Study consistently develops the current trend, which can be predicted in the short term. By 2010, renewables will contribute 15.5% of gross electricity production, rising to 27% by 2020. After that, according to the Lead Study, gross electricity consumption will fall from 612 TWh in 2005 to 595 TWh in 2010 and 570 TWh in 2020. The share of renewable-generated electricity will increase from 63.5 TWh in 2005 to 156 TWh in 2020 and is compatible with the renewal of Germany's entire power plant portfolio. Over time, the share of electricity generated by large hydropower plants and from biogenic waste – both of which fall outside the scope of the Renewable Energy Sources Act – will remain largely unchanged due to their limited potential for development. From 2020, however, increasing amounts of electricity will be fed in from the European interconnected grid. The generation of electricity from EEG-relevant systems will increase threefold to around 130 TWh in 2020 (see Fig. 14-2).

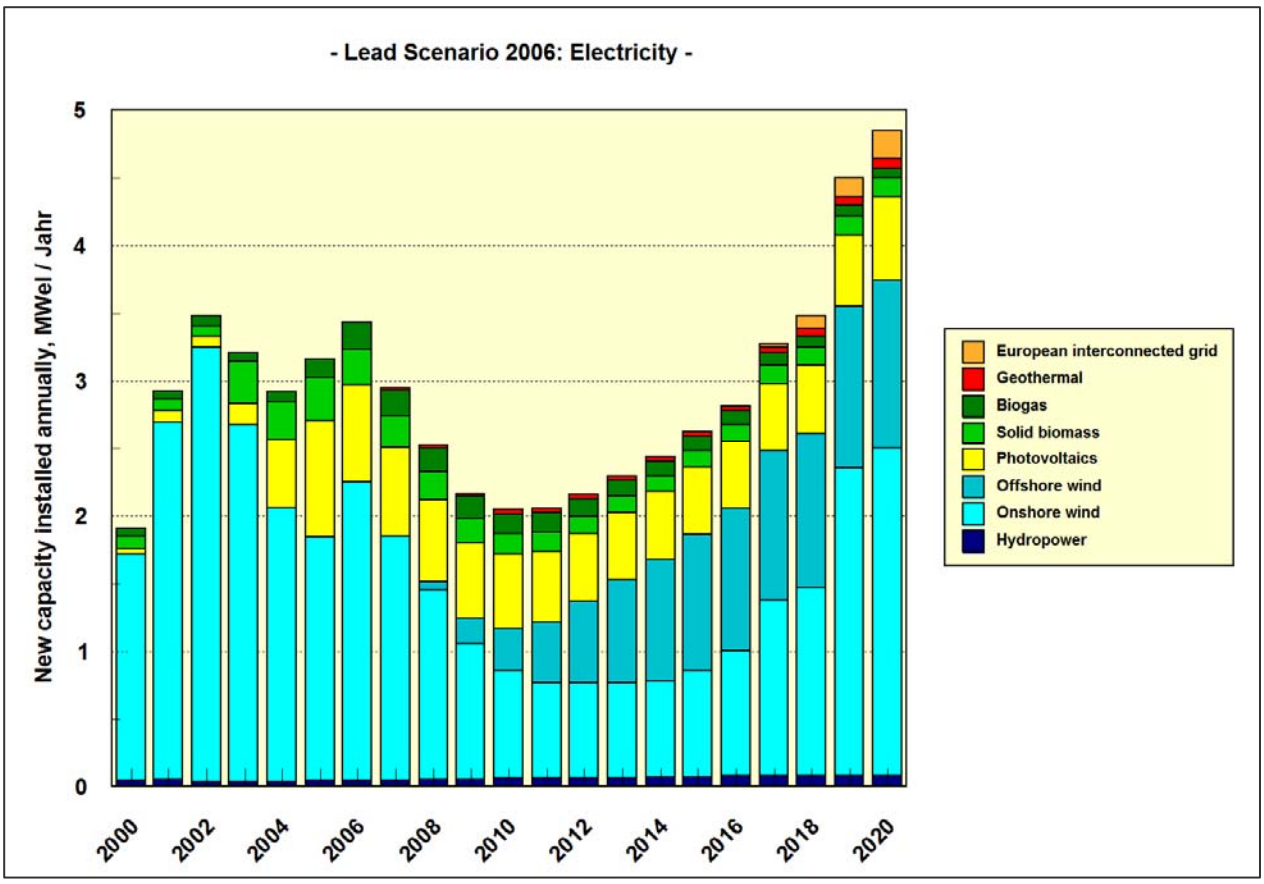


Fig. 14-1: Trends in new capacity installed annually for electricity generation from renewable energies for the period 2000-2020 according to the Lead Study [5]

While electricity generation from bioenergy carriers will increase threefold by 2020, the contribution made by onshore wind energy will only increase by around 50% over the next ten years; this expansion will result from the development of the remaining suitable sites and, above all, increased repowering. The development of offshore wind power will become far more important. In the scenario, it is assumed that offshore wind farms with a total capacity of 1,000 MW can be connected to the grid by 2011. This will establish the offshore sector's relevance to the energy industry, with fairly rapid expansion thereafter to 10,000 MW by 2020. Due to the higher electricity output achievable offshore, power generation from offshore wind systems will amount to around 33 TWh, a figure broadly equivalent to the onshore wind power generation predicted for 2007. Geothermal power generation – currently still in its infancy – will by 2020 contribute around 3 TWh from an installed capacity of 500 MW_{el}. It has the potential to expand far more rapidly after that date, however. The photovoltaic sector will by then be making a significant contribution to the power supply of around 8-9 TWh. However, the annual increase in new installed capacity will fall from 950 MW_p in 2006 to 400 MW_p in 2015.

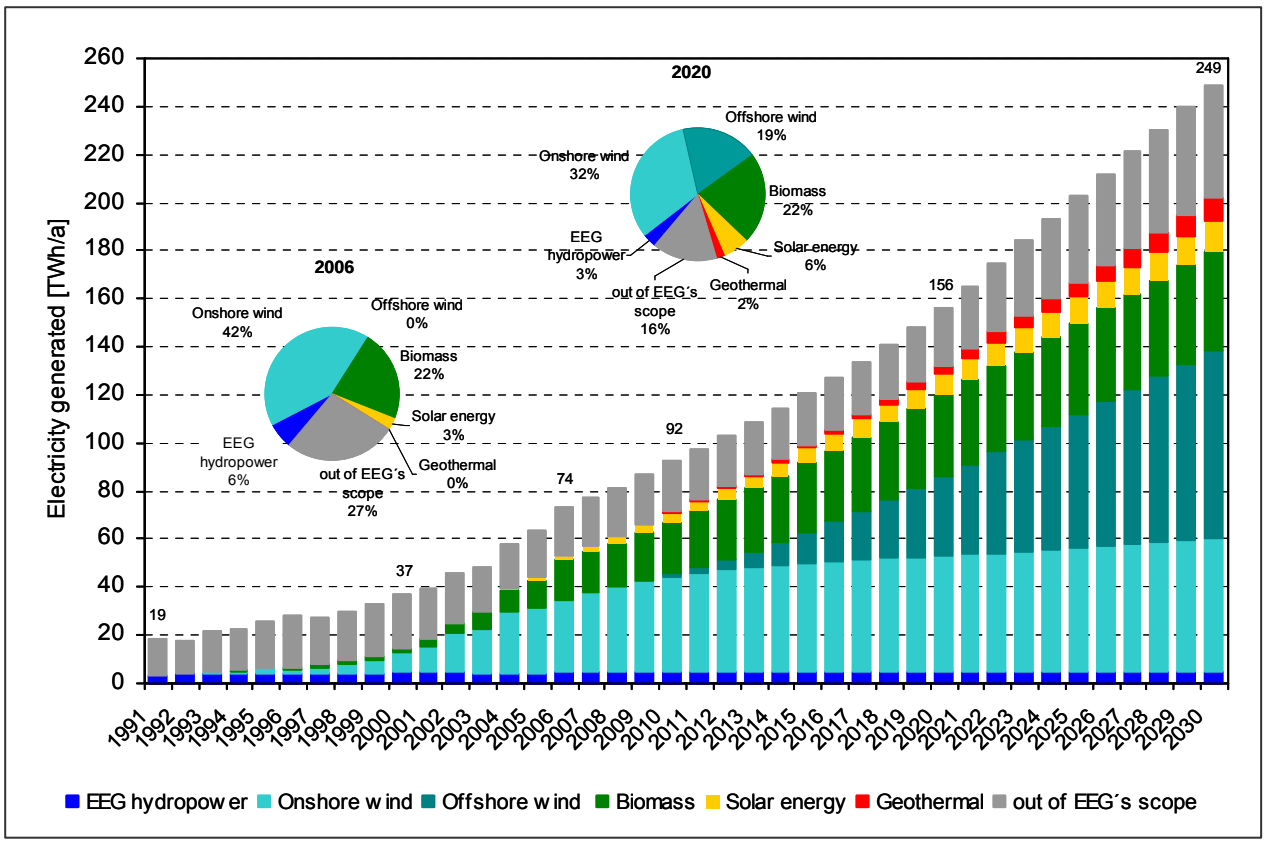


Fig. 14-2: Trends in electricity generation from renewable energies 1991-2030, based on the Lead Study [5]

14.2 Development of remuneration rates for and applicable value of renewable-generated electricity

The policy recommendations contained in this Progress Report will result in changes in the remuneration rates for renewable-generated electricity. Fig. 14-3 and Fig. 14-4 show the development of remuneration rates in specific renewables sectors for the year of commissioning, taking account of the recommendations contained in Chapters 6 to 11 which could be implemented from 2009 onwards.

For onshore wind energy, the tables show not only an increase in the initial fees but also the basic rates of remunerations, although in practice, these latter rates will only apply after a specific time period has elapsed. The "total biomass" curve is not a specific remuneration category under the EEG but is aggregated on the basis of structural changes within electricity generation from biomass. It is likely to significantly exceed the basic fees provided for under Article 8(1) of the Renewable Energy Sources Act, for in line with the Act's intended steering effects, it can be assumed that in future more facilities which generate electricity using innovative technologies – particularly using CHP and based upon cultivated biomass – will come into operation and claim the relevant bonuses, which now also should be subject to degression.

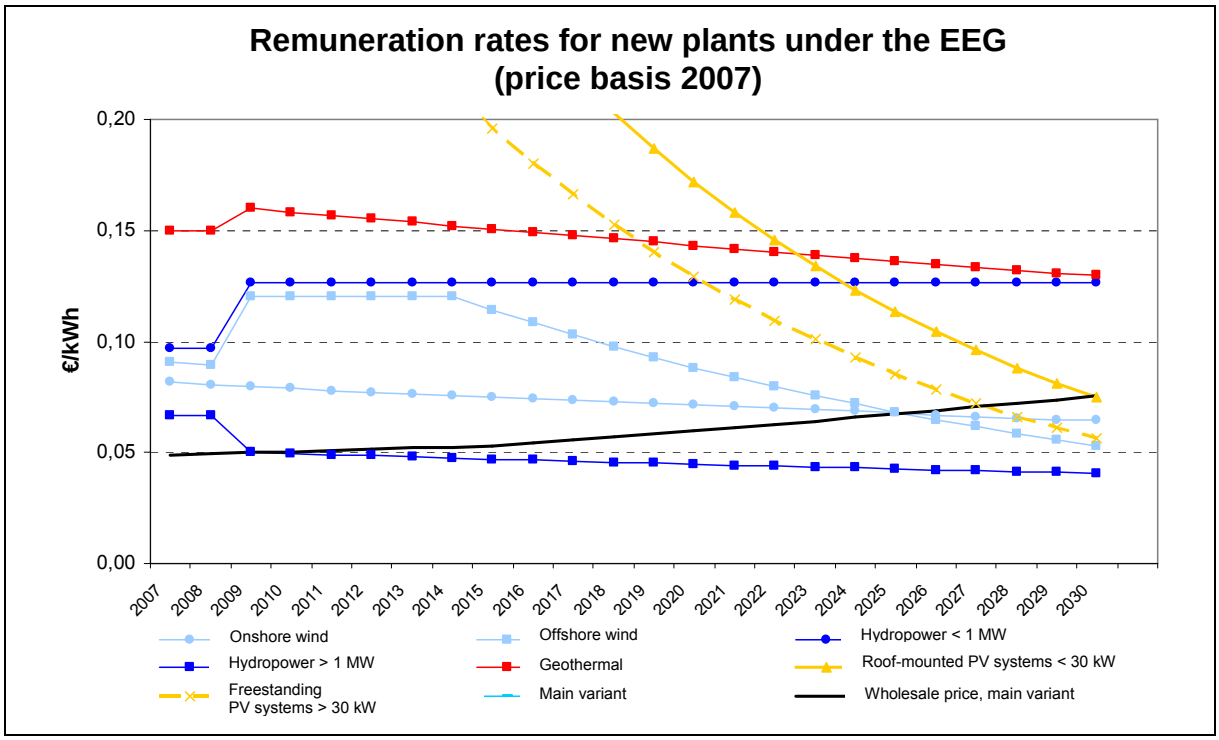


Fig. 14-3: **Development of remuneration rates under the Renewable Energy Sources Act for selected applications (excluding biomass) after the year of commissioning, based on the policy recommendations contained in the Progress Report (price basis: 2007).** [20]

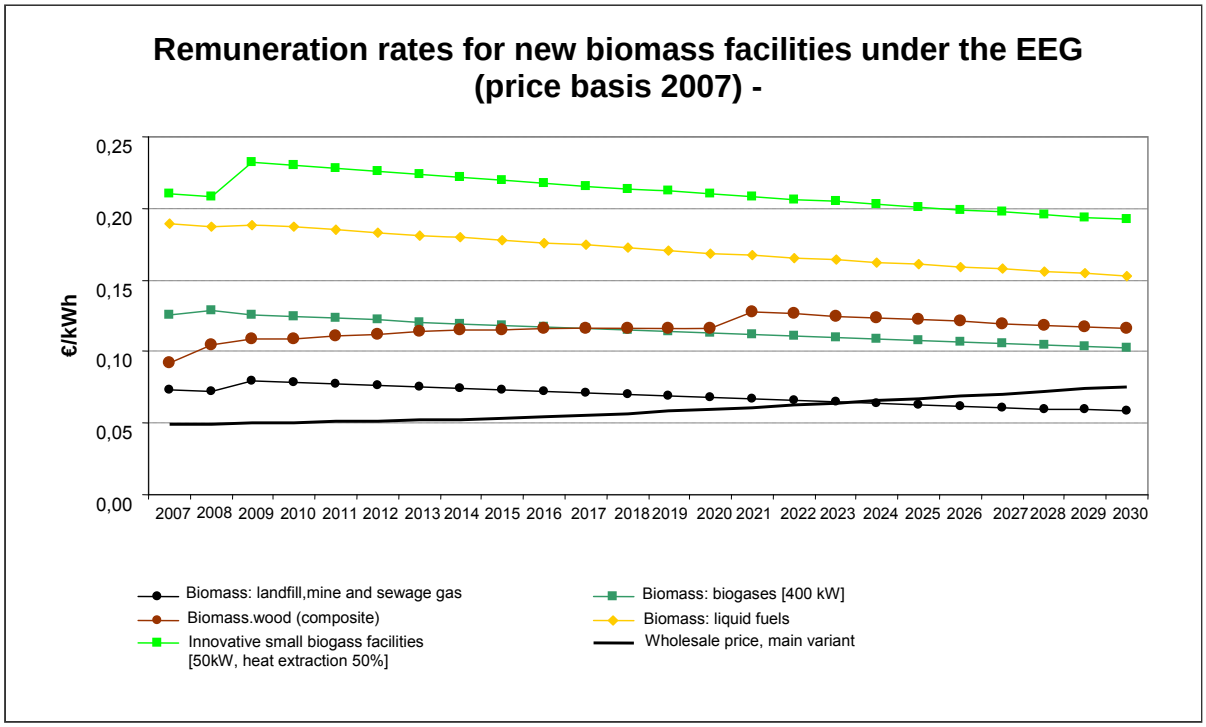


Fig. 14-4: **Development of remuneration rates under the Renewable Energy Sources Act for selected biomass applications after the year of commissioning, based on the policy recommendations contained in the Progress Report (price basis: 2007).**

[20] In the case of electricity from freestanding systems, under the current provision of the Renewable Energy Sources Act, fees are payable only if the installation was commissioned prior to 1 January 2015. This provision is not taken into account in Figure 14-3 in the interests of compatibility with the Lead Scenario.

The development of the remuneration rates for renewable-generated electricity under the Renewable Energy Sources Act is set against the applicable value of renewable-generated electricity, i.e. the average electricity purchase costs incurred by the electricity supply companies/grid system operators. Fig. 14-5 shows the anticipated development of electricity production costs (full costs) in Germany's future power plant portfolio as calculated in the Lead Scenario [5] in price path B: "moderate increase" and price path C: "significant increase".

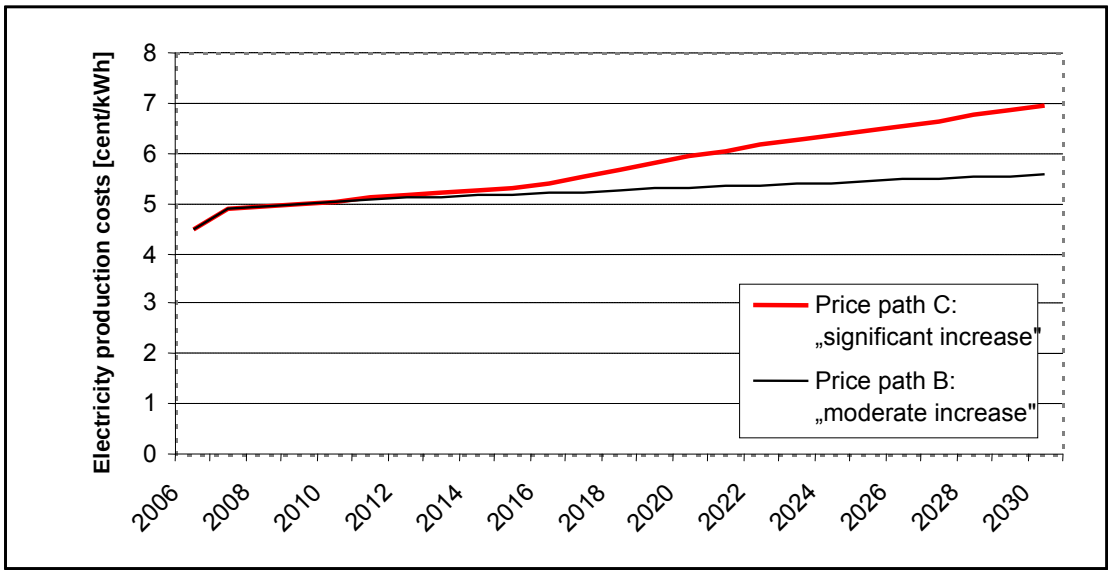


Fig. 14-5: Anticipated development of electricity production costs from fossil fuel-fired power stations, based on the Lead Study 2007 [5]

14.3 Climate and industrial policy impacts of the EEG

The Renewable Energy Sources Act is of key importance for climate protection, not only today but also in future (see also Chapter 2.2). Fig. 14-6 illustrates this using the expansion scenario. This shows that without the continued promotion of renewable energies in the electricity sector, the targets set for Germany under the Kyoto Protocol and Germany's more far-reaching national goals are not achievable. It is possible to reduce energy-related CO_2 emissions by 35% to 2020 if further measures are adopted that give equal weight to improving energy efficiency and utilising renewable energies. By 2020, around 100 million tonnes – i.e. some 30% – of Germany's total CO_2 emissions reductions will be attributable to the Renewable Energy Sources Act. The scenario also takes into account the fact that the CO_2 intensity of electricity production from fossil fuels will decrease by around 15% against the 2005 baseline due to more efficient energy use in power plants.

The Lead Study presents two model scenarios, one of which shows energy-related CO_2 reductions of 40% by 2020. This variant is based on ambitious policy measures being implemented in relation to renewable energies and energy efficiency. It also assumes that an improvement in energy productivity of 3% p. a. will be achieved – a significant increase compared with previous years. The Lead Study further assumes a shift in the fossil mix towards the greater use of gas, as well as the implementation on deadline of the nuclear phase-out pathway, enshrined in German law. According to the renewable energy scenario for working group 2 of the Energy Summit on 3 July 2007, similar renewables expansion rates and the implementation of the nuclear phase-out will reduce energy-related CO_2 emissions by more than 40%.

In Fig. 14-6, the CO_2 reductions achieved through this annual increase in energy efficiency are shown in blue (top right). The CO_2 reductions achieved through the expansion of renewables are shown in red (i.e. electricity generated within the scope of the Renewable Energy Sources Act) and green (i.e. electricity generated outside the scope of the EEG, heat from renewables, biofuels).

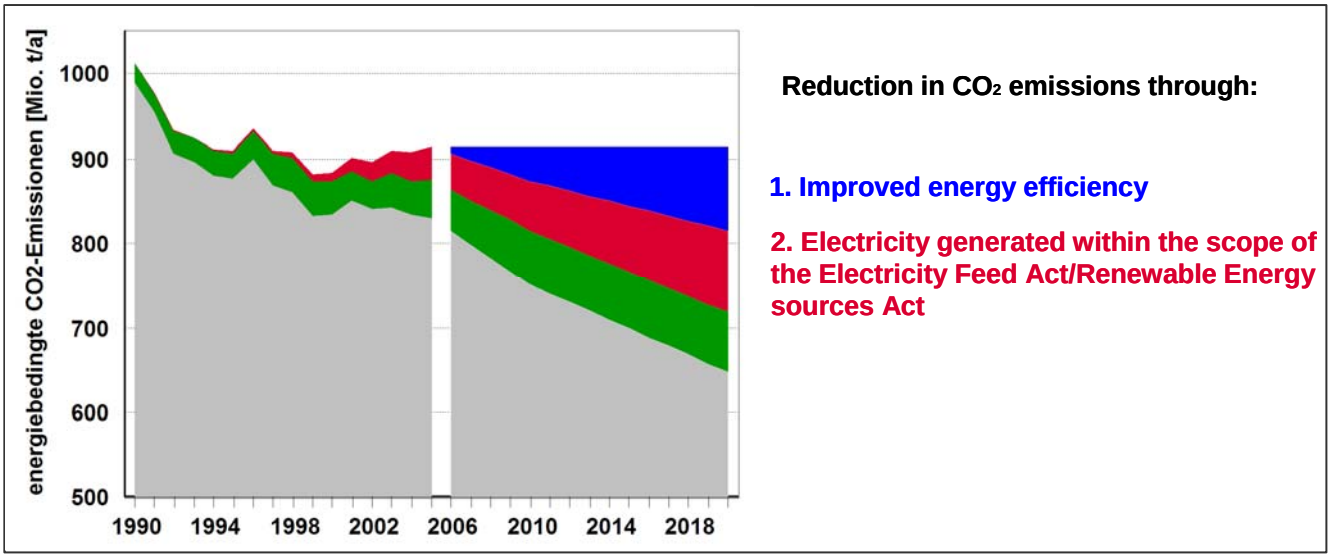


Fig. 14-6: Development of energy-related CO_2 emissions in Germany, 1990-2006, based on the assumptions made in [5]

The direct impacts of renewables expansion in the electricity market – and therefore also the Renewable Energy Sources Act – are also extremely important for Germany as a location for business and investment. First and foremost, this expansion is triggering substantial investment in new plant which, according to the scenario depicted in Fig. 14-1, is likely to total more than €150 billion during the period 2005-2020. Of this figure, more than €95 billion, i.e. 60%, are attributable to the Renewable Energy Sources Act (Fig. 14-7). In addition, there is the turnover generated by the operation and maintenance of EEG-relevant energy systems, which amount to around €54 billion, including the costs of bioenergy carriers, totalling €12 billion.

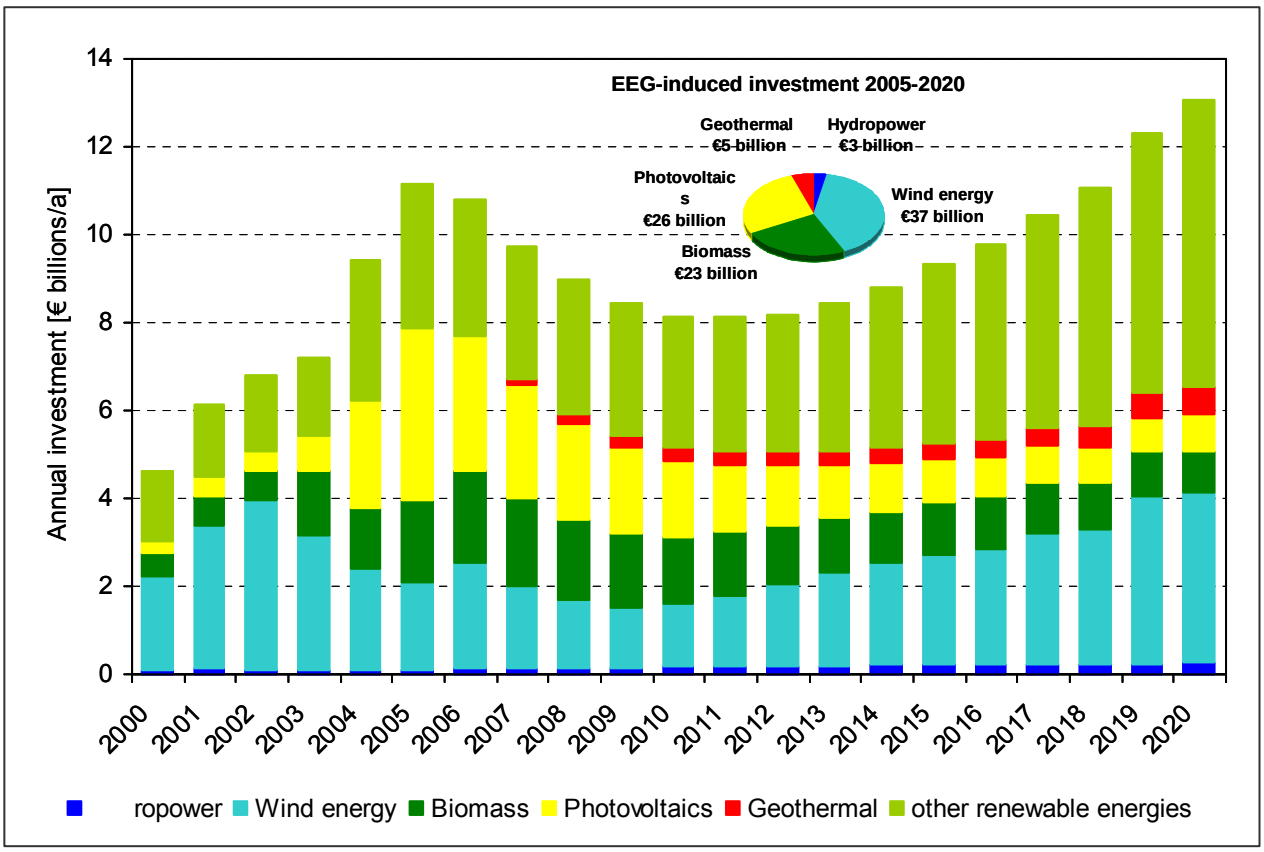


Fig. 14-7: Investment in systems for electricity generation from renewable energies, based on [5]

14.4 Policy recommendations

In recent years, the expansion of renewable energies has progressed more rapidly than generally anticipated. As a result, the target for 2010 – to achieve at least a 4.2% share of renewable energies in primary energy consumption by that date – was already achieved in 2005 and was exceeded by a substantial margin in 2006. Germany came close to achieving its target for the renewables share of gross energy consumption for 2010 – at least 12.5% – as early as 2006, reaching 11.6%, and exceeded it in 2007 with more than 13%.

On 9 March 2007, the European Council, under the German Presidency, set a binding target of a 20% share of renewable energies in overall EU energy consumption by 2020, which means a threefold increase compared with the 2005 baseline. The EU Member States will be required to meet different individual targets depending on factors such as the current share of renewables in their energy supply and their renewables development potential.

Germany's national expansion targets for renewables are to be adapted in line with the decisions taken at Meseberg on 23-24 August 2007. At its closed meeting in Meseberg, the Federal Cabinet agreed a future expansion target of 25-30% for renewable energies by 2020, to replace the current target of "at least 20%", with continued steady expansion after 2020.

Policy recommendations relating to the objectives of the EEG as stated in Article 1

Provisions within the scope of the Renewable Energy Sources Act

An increase in the targets for the expansion of renewable energies in electricity generation, as defined in Article 1 (2) of the Renewable Energy Sources Act, as follows:

- expansion target of 25-30% for renewable energies by 2020, to replace the current target of "at least 20%"
- continued steady expansion after 2020.

15 Annex

15.1 Overview of the methodologies used in the studies forming the basis of the Progress Report 2007

15.1.1 Studies commissioned by the BMU [1]

In a complex system such as that constituted by the full spectrum of renewable-generated electricity, the impacts of the Renewable Energy Sources Act can only be subjected to transparent and comparative analysis – and policy recommendations developed on that basis – if a joint analytical framework is applied. This requires the use of representative, practice-oriented reference systems, e.g. to determine the structure and development of electricity production costs. In order to create a viable data basis for this purpose, comprehensive surveys were carried out among plant operators, which were then compared with published cost data and empirical values from project partners. The plants' average electricity production costs are calculated by means of the usual dynamic investment calculation [61], so that using the selected approach, an overview can be gained of the average annual costs across the entire period under review. The direct comparability with the remuneration rates payable under the EEG is then obtained by means of differentiation according to remuneration categories, and the imputed operating life of the plants according to the specific remuneration period. The interest rate chosen for the purposes of the calculation, based on the interest rates weighted for the proportions of equity capital and borrowed capital used in the funding of the plants, is set at a nominal basic value of 8%. The specific characteristics in the individual renewables sectors necessitate the adaptation of the parameters in some cases, and this is shown in the graphic depiction of the electricity production costs. The definition of the electricity production costs at today's price (reference year 2006), and the discounting of future EEG remuneration rates, are based on an inflation rate of 2% p.a. In the graphic overview, the priority is to set the nominal electricity production costs against the nominal remuneration rates; however, in the interests of transparency, the real electricity production costs and real remuneration rates are also shown.

Similarly, to calculate the environmental effects, sector-specific emission factors are used for CO_2 and the "classic" air pollutants, and extrapolated along the time axis [62]. In this context, a distinction must be made between direct and total emissions. Total emissions include indirect emissions arising from upstream process chains such as plant manufacture and the fuel supply. In relation to the use of renewable energies, however, indirect emissions have relatively little significance in terms of their environmental impacts. Furthermore, it is also very difficult to calculate the indirect emissions due to the complex correlations involved. Against this background, they will only be taken into account in exceptional cases where relevant.

A key factor when calculating the environmental effects is the reduction of CO_2 emissions achieved through the use of renewables. In the electricity sector, the expansion of renewables will progressively replace electricity generated from fossil-fuel power stations (especially coal-fired power stations), reducing CO_2 emissions accordingly. The Working Group on Renewable Energy Statistics (AGEE-Stat) has identified various emission factors here based on research findings. For example, in 2006, CO_2 emissions were reduced by around 922 g for every 1 kWh of conventional electricity substituted by renewables. Every 1 kWh of fossil-generated heat replaced by renewable-generated heat cut CO_2 emissions by 232 g in 2006, while every 1 kWh of fossil fuel substituted by renewables cut around 319 g of CO_2.

While resource conservation and climate protection were already key environmental goals in the 2000 Renewable Energy Sources Act, the new EEG, which came into force in 2004, contains specific provisions on nature conservation and environmental protection. The process for the environmental evaluation of the benefits of renewables use for nature and landscape as set out in Article 20 (1) of the Renewable Energy Sources Act is shown in Figure 15-1. The environmental objectives defined in the EEG are the starting point; these generally relate to the desired environmental effects to be supported or achieved through renewables expansion. In many cases, however, they cannot be achieved directly and exclusively through the EEG, but are influenced by other instruments, such as those applied in the licensing of plants or the cultivation of biomass. Account has been taken of this in the analysis.

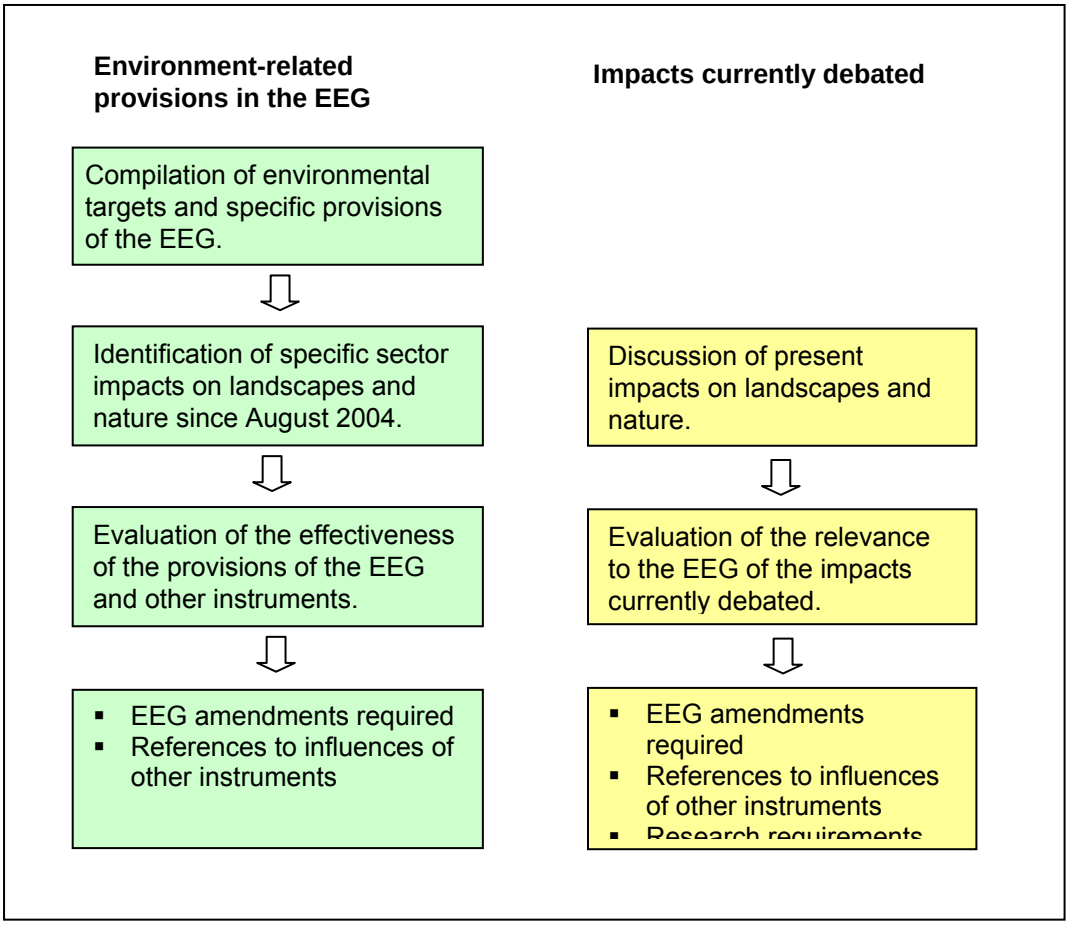


Figure 15-1: Process of environmental evaluation [1]

15.1.1.1 Methodology used for model calculations

To calculate the electricity production costs, an investment calculation using the annuity method is carried out for the various renewables sectors, with the exception of wind power. The annuity method is a method of dynamic investment calculation. Using this procedure, one-off payments and periodic payments of varying amounts can be translated into constant, i.e. average annual payments. The annuity factor used here is a function of the imputed interest rate and the review period for the calculation, which allows varying payment times to be taken into account.
For wind power, on the other hand, the net present value method is used so that account can be taken of sector-specific characteristics, especially the large variations in the payment streams within the review period.

For its part, the annuity method is actually a further development of the net present value method, so the results are comparable despite the different methodology [61].
All costs are initially determined on a real basis, i.e. adjusted for inflation, and the reference year for the cost calculation is 2006. This allows a direct interpretation of the calculated costs as these can be compared directly with other values related to 2006. To verify the profitability of plants generating electricity from renewables, costs have to be set against the revenues. The EEG does not provide for inflation to be either considered or offset, so the remuneration rates are set at a nominal constant value. The electricity production costs constitute an average value as they are determined on an imputed basis by means of the annuity method over an imputed calculation period (remuneration period according to the EEG). In order to compare electricity production costs (for the reference year 2006) and the remuneration rates according to the EEG for commissioning in 2006, the electricity production costs determined on a real basis have to be translated into nominal values by applying a nominal inflation rate of 2% p.a. This allows the calculated average nominal costs to be compared directly with the EEG remuneration rates.
However, the nominal remuneration rates are exposed to inflation across the entire period under review and therefore decline in real terms. Therefore, to avoid misunderstandings and misinterpretations, the annual inflation rate is also taken into account when calculating the real remuneration rates. This allows both the nominal remuneration rates to be compared with the nominal electricity production costs and the real electricity production costs to be compared with the real remuneration rates.

15.1.1.2 Input data used

To calculate the electricity production costs, representative, practice-oriented model applications falling within the EEG's scope of application were defined. In order to define the model cases, based on the plants currently in operation, the main types of facilities anticipated in new plants were determined, which were essentially differentiated by

- the plant's output for hydropower, landfill, mine and sewage gas, biomass, geothermal and photovoltaics (in each case, the various capacity classes capture the remuneration steps),
- the location for wind energy (e.g. offshore, onshore etc.) and photovoltaics (roof-mounted/freestanding systems etc.),
- the inputs / fuels used for solid, gaseous and liquid biomass and for landfill, mine and sewage gas (e.g. logging residues or wood waste in the case of solid bioenergy carriers, etc.),
- and, if appropriate, the technologies used (conventional technology, innovative technology such as Organic Rankine Cycle (ORC) etc.).

A technical reference is specified and calculated for each model case. This is done on a representative basis, i.e. by establishing typical values and boundary conditions. Empirical data from project partners, information from operator surveys and literature and results from other BMU studies are applied to establish the technical parameters and cost values (i.e. investment costs, costs for input materials, other operating costs, and, where appropriate, returns from heat supplied).

Investments

The investment costs include all the costs incurred in producing a complete plant that is ready for commissioning, including additional costs for planning, approvals, interest during construction etc.:

- Investment costs for
  - Machinery,
  - Electrical and control systems,

- Construction (buildings, site installations etc.),
- Connection to the infrastructure (grid connection including transformers, water supply, wastewater management etc.).

- Related costs for
  - Consultants, planning (including owner's own contribution), obtaining approvals, monitoring assembly, construction and commissioning,
  - Raising capital and funding, including interest during construction.

Operating costs

The following principal operating costs are incurred in the operation of renewable-generated electricity plants:

- Fuel costs in the case of biomass, mine, landfill and sewage gas,
- Service costs (maintenance and repairs),
- Personnel costs for technical plant operation,
- Insurance, administrative and leasing costs,
- Other variable costs for supplies (e. g. additional water, lubricating oil, dosing equipment for water treatment etc.), as well as to cover the plant's own electricity requirement and disposal of residual materials.

The operating costs used during this study should (with the exception of the maintenance costs for wind energy plants, see below) all be seen as mean values over the plant's operating life. This means that real, constant values are applied each year, which only rise with the general price increase rate over the plant's operating life. Admittedly, experience shows that individual operating costs, especially for maintenance, service and repairs, vary from operating year to operating year. However, this effect cannot be sufficiently quantified and is therefore not taken into account. The exception here is the maintenance costs for wind energy plants; these costs rise significantly in the second half of the plant's operating life due to the requirement for replacement investments, and this is reflected in the calculations.

Table 15-1 below contains a summary of the basic data and parameters used for the profitability calculations, and the selected cost estimates for the individual renewables sectors.

Table 15-1: Summary of the basic data and parameters used for profitability calculations [1]

	Hydro-power	Biomass	Landfill, sewage and mine gas	Geo-thermal	Wind	Photo-voltaics
Imputed period under review	30 a / 15 a	20 a	Basic case: 20 a (6 a variant for landfill gas)	20 a	Basic case: 20 a (variant: 16 a)	20 a
Nominal composite interest rate	Small plants 7%/a Large-scale plants 8%/a		8%/a	8%/a	8%/a	Variation within sector 5 - 8%/a
Inflation rate	2%/a					
Remuneration for heat (for CHP; ex-plant)	Basic case: € 25 /MWh (Variation within sector €10 - 40 /MWh)					
Specialist personnel costs	€ 50 T per person-year					
Equivalent operating hours at full capacity of electricity-led plants	Dependent on degree of utilisation	7,700 h/a	Landfill gas 7,000 h/a, sewage/mine gas 7,700 h/a	7,700 h/a	Dependent on conditions at location	
Equivalent operating hours at full capacity of heat-led plants	-	Dependent on model case	-	-	-	-

15.1.1.3 Treatment of revenues

When calculating electricity generation costs for plants that generate both heat and electricity, the total costs per annum should be split between these two products. In the case of renewables, this is especially true for plants that use solid and liquid biomass, biogas, sewage gas, landfill and mine gas. In such cases, therefore, the "residual costs of electricity generation" are calculated by deducting the heat payments from the total costs to receive the actual costs attributed to electricity as a product.

15.1.1.4 Treatment of investment cost subsidies

The calculations do not take account of support measures such as investment cost subsidies, for example.

15.1.1.5 Interest on capital employed and for inflation

An imputed review period is used as a basis for all the models, which corresponds to the values for the duration of the remuneration commitment established in Article 12 (3) of the EEG (20, 30 or 15 calendar years plus the year of commissioning).
Two or three different values – primarily depending on the plant's output – are applied to produce the nominal, imputed composite interest rate (without tax effects), in order to obtain maximum comparability of results and also to take account of the real circumstances. Thus, for example, a lower composite interest rate is normally applied in the case of small plants

constructed by private operators than for large-scale plants. This is because the smaller operators usually have a higher proportion of borrowed capital, lower-interest loans and usually lower profit expectations.
A profit based on the equity capital employed is incorporated into the calculations by selecting an appropriate equity capital interest rate.
All costs are initially determined on a real basis, i.e. adjusted for inflation, and the reference year for the costs is 2006. This allows a direct interpretation of the calculated costs as these can be compared directly with other values related to 2006. The costs are set against the remuneration rates applicable for commissioning in 2006 pursuant to the EEG. As these are nominal, constant values, i.e. are declining in real terms (taking account of the price increase rate), the nominal values are calculated and portrayed along with the real electricity generation costs.

15.1.1.6 Tax charges and benefits

As in similar surveys, taxes on transactions (turnover or land transfer taxes) and revenue-related taxes (income taxes) are not included in the model calculations carried out in this study, i.e. a pre-tax calculation will be used.
This procedure was chosen as the estimations of the (individual and significantly varying) rates of taxation which would otherwise be required would give rise to a potentially substantial source of errors. Ascertaining the precise profit-related taxes imposed requires the production of annual accounts and thus entails a detailed business assessment of each investment.

15.1.2 Studies commissioned by the BMWi [14]

15.1.2.1 Methodology for model calculations

A standard process is used for all model calculations. This is a calculation model developed at the IE institute for the profitability calculations of electricity generation plants. The process used constitutes an annuity method and corresponds to the VDI 2067 standard in combination with the VDI 6025 standard. This allows all input data across all systems to be uniformly considered in the study.

15.1.2.2 Input data used

The comparability of model results depends primarily on the quality of the input data. In addition to the statements made in Chapter 2 (Overview of the Development of Renewable Energies in Germany), further research was carried out in order to obtain comparable input data for all energy carriers. The selection of input data is based partly on data from ongoing IE projects and partly on literature sources. The sources chosen here are those that, on the one hand, supplied sufficiently precise information on the individual items related to investment and operating costs, and on the other hand, provided plausible values compared to other sources (to avoid anomalies).
The sources used are shown individually in the relevant sub-sections to ensure a high level of transparency.
Electricity production costs are calculated for practice-oriented model cases and a technical reference is specified for each case. Values and parameters typical for the sector are used as a basis here. However, in specific individual cases, these parameters, and therefore also the profitability of the plants, can deviate significantly from the model cases examined in this study.

All model cases are assumed to be freestanding, newly constructed plants on greenfield sites with the potential to be connected to existing infrastructure (public electricity supply grid, water supply, waste disposal systems etc). Site procurement costs are not taken into account, nor are additional technical facilities such as peak load boilers to cover peaks in heat demand. Any additional costs for heat distribution are also not taken into account. This is permissible as a value is fixed for achievable heat remuneration which is understood as ex-plant (i.e. excluding heat distribution) and takes no account of peaks in demand (for which comparatively high remuneration can be achieved)[63]. An exception is made in the case of hydropower where account is also taken of the repowering of old plants along with the construction of new plants. This is appropriate as only very few plants have been newly constructed in the last 10 years. The majority of plants connected to the network have been old plants that have either been repowered or modernised. These incur significantly lower investment costs.

All the costs and prices used are average values and are based on empirical values, recommended price offers from plant manufacturers or publicly accessible statistics or literature that has been analysed in the course of this study and checked for plausibility. Own data surveys completed during ongoing projects and IE publications were also used. It must be noted that the cost estimates selected are inevitably exposed to a fluctuation margin and that significant deviations are possible in specific cases. For example, investment costs in particular are dependent on location. Operating and consumption-related costs are taken as constant mean values across the period of review, which are only exposed to the price increase rate.

In the following section, the cost groups examined in this study (in line with the VDI 2067 standard) and their input parameters are explained in more detail. Figure 15-2 gives an overall view of the methodology for calculating electricity production costs.

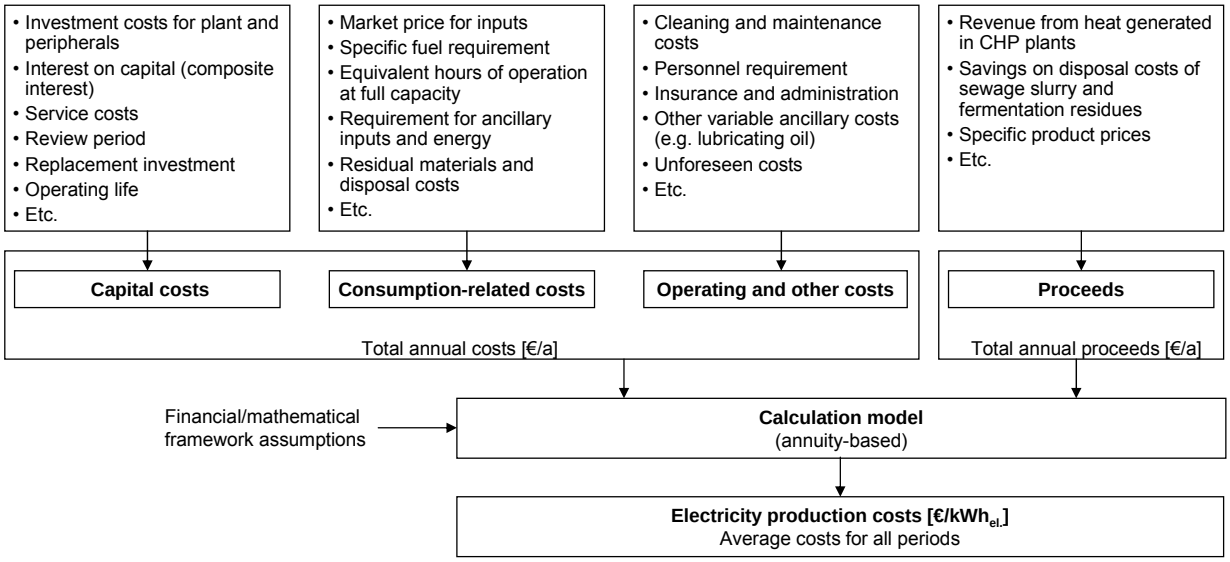


Figure 15-2: Methodology and input variables for calculating electricity production costs

- **Capital costs:**

  Capital costs comprise investment costs and service costs. No account is taken of investment subsidies or other support measures (see Section 4.1.5).
  - The investment costs applied in the calculation include all necessary costs (structural and technical facilities, supply and disposal lines and network connections) required to produce a complete plant that is ready for commissioning, including ancillary costs (planning, approvals, raising capital and funding etc.).
  - Service costs are put at 1% of the specific investment costs for buildings and built structures and 2% for engineering systems. Furthermore, replacement investments within the relevant review period (generally 20 years) are included with reference to the individual operating life[18] of structural and technical components.

- **Consumption-related costs:**

  These are particularly significant in the case of bioenergy plants. The following costs are incurred:
  - Fuel and/or substrate costs, unless they can be provided free of charge within the operation (e.g. saw mill residue or liquid manure):
    - Logging residues € 50/t (calorific value: 3.30 kWh/kg)
    - Wood from landscape management €10/t (calorific value: 2.2 kWh/kg)
    - Wood waste: €17/t (calorific value: 3.42 kWh/kg) assumed in the case of co-firing with wood waste (the wood waste-AIV fraction is generally not more than 10%); the prices for pure wood waste fluctuate between € 0-30/t
    - Rapeseed oil €0.65/l and palm oil € 0.45/l (calorific value: 9.6 kWh/l, prices ex-plant)
    - Maize silage € 25/t (biogas yield: 198 m^3/t_{solid})
    - Organic waste (biogas yield: 110 m^3/t_{solid}), see proceeds

  - The plant's own electricity requirement: taken from the public supply grid depending on the amount of energy used – set at 6 to 12 ct/kWh
  - Use of ancillary inputs (e. g. engine or heating oil, additional equipment for flue gas treatment, water treatment)
  - Disposal costs of residual materials (e. g. ash € 50/t[19])

- **Operating costs:**

  The following costs are considered as operating costs:
  - Maintenance and cleaning costs: generally included as 1% of investment costs or as a lump sum cost for full maintenance contracts (e. g. in the case of small-scale CHP units fired with plant oil)
  - Personnel costs for technical plant operation: the figure of €50,000 per year and person is estimated for one full-time employee; the number of employees is set on the basis of the research carried out (depending on the technology being deployed in the plant, the installed capacity and, if applicable, the cost of fuel preparation, for example). Where lower-paid workers are used (in the biomass area), their wages are converted accordingly.

- **Other costs:**

  Insurance and administrative costs along with other variable ancillary costs (e.g. lubricating oil, dosing equipment for water treatment, lump sums to cover costs for unforeseeable repairs) are included as "other costs" in the review. In the case of bioenergy plants, 1% of the investment costs is imputed for insurance with a further 1% for variable plant costs; these values are identified individually for the other technologies as well. One exception here is the organic waste fermentation plants where the other variable costs are put at 2.5%.

15.1.2.3 Treatment of proceeds

When calculating electricity generation costs for CHP plants, the total costs per annum are to be split between the two products. In such cases, therefore, the "residual costs of electricity generation" are calculated, where the heat remuneration is deducted from the total costs to elicit the actual/resulting costs of electricity generation (i.e. taking account of the proceeds/credits for heat supplied). Finally, for illustration purposes, the nominal electricity production costs (i.e. taking account of the inflation rate) are set against the remuneration rates laid down in the EEG, as the wording of the law states that these remain nominally constant (i.e. decline in real terms) over a period of 20 years for the plants concerned.
Proceeds: In the case of CHP plants, remuneration is given for the heat used externally (i.e. excluding the plant's own heat requirements) and this is deducted from the total costs to elicit the actual costs incurred for electricity as a product.

Remuneration for heat supplied corresponds to:

- where the heat is used to meet the plant operator's own heat requirements: the costs the operator would incur for alternative fossil-generated heat;
- where third parties are supplied or heat is fed into existing district or local heat networks: the average achievable market prices (set here at €25/MWh).

Furthermore, where organic wastes are fermented disposal credits can be applied. In this study, credits of €60 /t_{solid} of organic waste were applied, which included the potential commercial sale of the fermentation residue as compost. Where electricity is produced from sewage gas, the disposal costs that were avoided are regarded as proceeds and presented separately.

15.1.2.4 Treatment of investment cost subsidies

No investment cost subsidies are available for building renewable-generated electricity plants that can feed electricity into the grid in accordance with the EEG. Research has shown, however, that potential plant operators can obtain investment cost subsidies in individual cases, but there are regional differences here. This happens when, for example, individual *Länder* take a pioneering role in the use of certain innovative technologies (e.g. biogas plant feeding into the gas network). Subsidised training is also offered to future bioenergy plant operators, and completion of these training courses has a positive impact on financial negotiations and therefore also on interest rates on borrowed capital. The above benefits, however, vary greatly from region to region and cannot be generalised in the type of general overview conducted in this study.
A review of the terms and conditions of the market incentive programme showed that the investment cost subsidies available only applied to plants of under 100 kW, which generally do not generate any electricity. Therefore none of the model cases defined meets the criteria for these investment cost subsidies. No investment cost subsidies are offered by the KfW banking group.

15.1.2.5 Interest on capital employed and for inflation

The comments made in the previous section notwithstanding, various low interest-rate programmes[20] are available from the *Kreditanstalt für Wiederaufbau* (KfW banking group) which can be considered here. Interest rates of between 3 and 7% are offered, mostly up to 5% depending on the overall risk, the profitability of the project, creditworthiness and proportion of equity capital. A composite interest rate of 5% has been assumed for all the model cases calculated in this study. Geothermal projects are subject to a composite interest rate of 7% as these are very high-risk projects for which KfW also charges a higher rate of interest.

The general price increase rate reflects inflation. A 1% inflation rate is assumed for capital costs and 2% for operating, consumption-related and other costs; these levels are recommended by VDI 2067. Real price increases (future market prices) are not included.

15.1.2.6 Tax charges and benefits

The calculation does not include any tax charges or benefits as the resultant estimations of the (individual and significantly varying) rates of taxation would give rise to a potentially substantial source of errors. All calculated production costs therefore portray the pre-tax operating results of the plants. Regardless of how the investor is subject to taxation at a later date (with or without depreciation or amortisation possibilities), operating results thus cannot be improved by special tax benefits or by offsetting profits and losses for tax purposes. In the best-case scenario, the calculated operating result is untaxed and retained in full, and in the worst-case scenario the profit achieved, from the perspective of the operator, is taxed at the full rate payable by the operator and therefore reduced.
In the wind power sector, opportunities for tax write-off have become an important factor in the investment decisions of many investors in recent years. In terms of the model cases calculated, this means that where favourable tax write-off opportunities are available, all or most of the operating result is retained as profit.

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