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Research Report

Current and prospective costs of electricity generation until 2050

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IMPRESSUM

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Current and Prospective Costs of Electricity Generation until 2050

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Corrected Version

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Executive Summary

1. This document provides a comprehensive survey of current and future cost estimates in the electricity sector, covering renewable and conventional generation. Among the various cost estimates available, we focus on the production costs, including capital costs, fixed and variable operation & maintenance costs (O&M), and variable costs; in addition, we provide estimates on plant availability, technical lifetime, and operational flexibility.

2. The objective of this document is to provide a unified dataset that can be used for model comparisons. DIW Berlin, TU Berlin, and the Reiner Lemoine Institute are currently involved in various studies on future energy system development. The standardization of the cost assumptions should provide a comprehensive common dataset, and thus add value to modeling exercises and comparisons.

3. In making the use of data transparent, the document aligns with the "Ethical code for appropriate scientific behavior for economists" set out by the Verein für Socialpolitik (VfS 2012) for German speaking economists, requiring, amongst other things, that research be transparent and tractable, and that data, source code, and results be made publicly available; it is also in line with the disclosure policy of the American Economic Association (AEA 2012).

4. The following table summarizes the most important findings and estimates on generation technologies. Based on an assessment of available data, we propose the following set of costs for the use in models.

5. All-in-costs (Levelized Cost of Electricity, LCoE) and their composition as a function of dependence of full load hours are illustrated below. A 9% discount rate is assumed with 2010 fuel prices (IEA 2011b) and a CO_2 price of 20 EUR/t. EEX prices help to identify the range at which power plants would be profitable. Even at high use factors, power plants hardly generate profits from "energy-only markets" under 2010 EEX prices. Nuclear power is not competitive in any case, with all-in-costs of around 100 EUR/MWh at 8000 full load hours; this does not yet include insurance costs.

	Capital cost in 2010 EUR/kW	2010	2020	2030	2040	2050
WIND	Onshore	1300	1240	1182	1127	1075
	Offshore	3000	2742	2506	2290	2093
SOLAR	PV	1560	750	600	472	425
	CSP	3500	2841	2307	1872	1520
BIO	Biomass	2500	2350	2209	2076	1951
GEO	Geothermal	4200	3775	3392	3049	2740
HYDRO	Pump storage or reservoir**	2000	2000	2000	2000	2000
	Run-of-river	3000	3000	3000	3000	3000
MARINE	Wave and Tidal	5000	4246	3605	3062	2600
NUCLEAR	Nuclear – Generation 3[1]	6000	6000	6000	6000	6000
COAL	Coal – IGCC w/o CCTS	1800	1800	1800	1800	1800
	Coal – IGCC w CCTS[2]	3200	3124	3052	2984	2920
	Coal – PC w/o CCTS (Advanced/SuperC)	1300	1300	1300	1300	1300
	Coal – PC w CCTS (Advanced/SuperC)	2700	2624	2552	2484	2420
	Coal – PC w/o CCTS (Subcritical)	1200	1200	1200	1200	1200
	Coal - PC w CCTS (Subcritical)	2600	2524	2452	2384	2320
	Lignite – Advanced (BoA) w/o CCTS	1500	1500	1500	1500	1500
	Lignite – Advanced (BoA) w CCTS	2900	2824	2752	2684	2620
GAS	Gas CC w/o CCTS	800	800	800	800	800
	Gas CC w CCTS	1400	1367	1337	1308	1280
	Gas Combustion Turbine w/o CCTS	400	400	400	400	400
	Gas Combustion Turbine w CCTS	1000	967	937	908	880
	Gas Steam Turbine w/o CCTS	400	400	400	400	400
OIL	Oil Combustion Turbine w/o CCTS	400	400	400	400	400
	Oil Steam Turbine w/o CCTS	400	400	400	400	400

* CCTS costs are reported for 2010 although the technology is not yet available for commercial applications

** Pump storage is usually more expensive than reservoir storage. Investment cost also depends on storage size

Table 1: Capital costs of electricity generation technologies.

Source: Own compilation, based on literature survey and expert opinion

[1] Note that nuclear capital cost includes decommissioning and waste disposal.

[2] CCTS operation and maintenance costs include the cost of carbon transportation and storage.

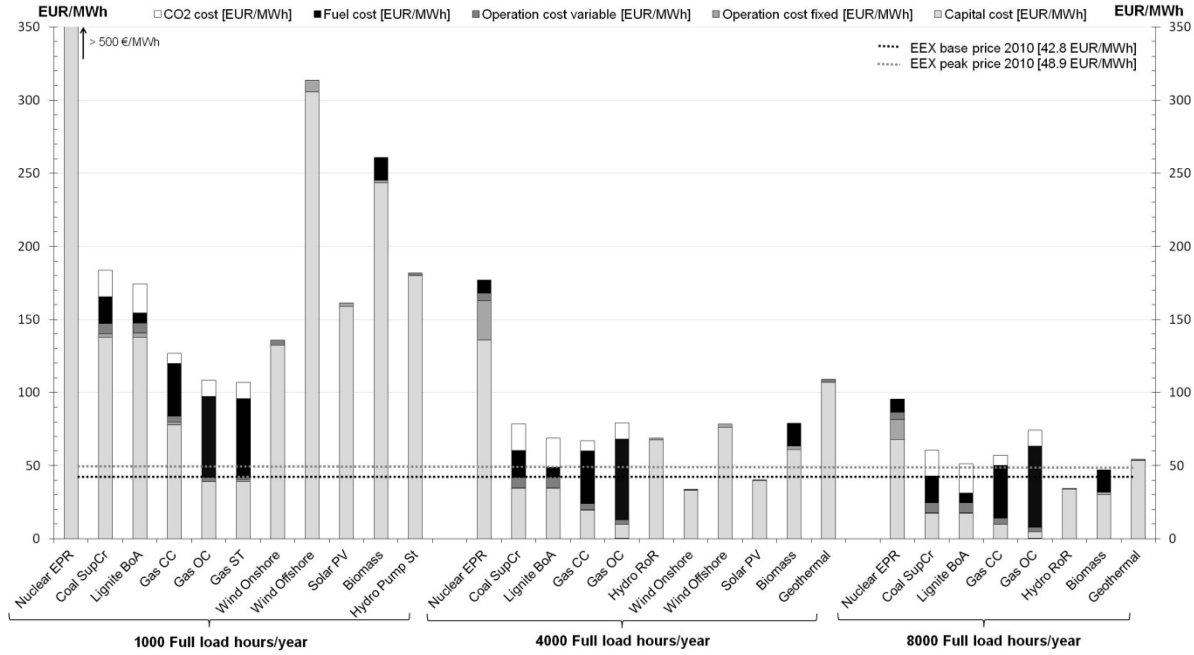

Figure 1: Illustrative levelized cost of electricity generation.

Source: Own illustration

1 Introduction

1.1 Motivation

Assumptions of costs for electricity generation are an important input for quantitative energy models, and they are particularly important for longer term assessments regarding the future energy system. This study provides a survey of cost estimates that covers a broad range of the existing literature; from these various estimates we derive a set of cost parameters for the period 2010-2050 that we consider to be appropriate for energy models. Since most cited reports are Europe-based, the literature review and cost proposal is most suitable for model applications to Europe.

Our estimates focus on the production costs of electricity generation, mainly capital costs and fixed and variable operation and maintenance costs; where appropriate we also include CO_2-emissions. We consider technical parameters such as technical lifetime, availability factors, thermal efficiency rates, etc.

The report is structured in the following way: section 2 focuses on renewable energy technologies, while section 3 deals with thermal technologies, i.e. nuclear and fossil fuel-fired power plants. Section 4 compiles information on further technical parameters e.g. availability, lifetimes, construction times and technical operational flexibility. In section 5, a likely evolution of costs and technical parameters is outlined for the period 2010-2050. The conclusion contains the full set of cost estimates for 2010-2050 that we suggest for future use in energy models.

1.2 Definition of cost

In this report, capital cost is considered as “Greenfield” and “overnight” investment cost, comprising the construction of a power plant excluding all interest effects. The report makes no assumption about financing cost and sources of capital as these are highly specific to the individual investor. As in Energinet (2012), we consider capital cost as engineering, procurement and construction cost (EPC). That means no costs of infrastructure connections (fuel, water, power grid) are accounted for. Additionally no costs of permission and land acquisition and environmental approval requirements are considered explicitly. Later (discounted) deconstruction of a plant is not included in the cost estimate and it is argued that the residual value of the plant covers deconstruction cost. An exception is made for nuclear power, where deconstruction is more complicated. For nuclear power, deconstruction cost is included in capital cost as upfront deposit payment. The price level of cost estimates in the literature overview is not harmonized, but projections on our own account are harmonized at 2010 price levels.

Discount rates play an important role in long-term investment decisions.[3] A discount rate of 9% is assumed for the power sector in EC (2011). 5% and 10% discount rates are tested in IEA et al. (2010). All calculations here are based on a 9% (private) discount rate, consistent with current PRIMES assumptions. Since capital cost is considered as “greenfield” and “overnight” investment cost the report makes no assumption about financing cost and sources of capital. Furthermore financing costs are highly specific to the individual investor and thus difficult to generalize.

1.3 Definition of operation and maintenance cost

The operation and maintenance (O&M) costs of power generation have fixed and variable components. Fixed O&M consists primarily of plant operating labor and regular and irregular maintenance work (Konstantin 2007, p.293) but also property tax, insurance and network use of system charges (Energinet 2012, p.15). Its value is highly dependent on the operating cycle and staffing philosophy of the plant. Variable O&M cost arises due to a constant maintenance contract and it includes periodic inspection, replacement, repair of system components and consumables, disposal of residuals and auxiliary materials (water, lubricants, fuel additives) (Energinet 2012, p.15).

1.4 Other assumptions

Note that the study is limited to the private production costs and, hence, ignores other important categories, such as <u>social</u> costs and <u>transaction</u> costs: social costs refer to the externalities generated by electricity, e.g. environment, noise, etc. where we only include estimates of CO_2-costs. Transaction costs refer to the costs of “running the institutional system”, and consist of market, political, and administrative transaction costs; these may make up over 50% of total costs (Wallis and North, 1986). <u>Insurance</u> costs are normally an element of the fixed costs, but are hardly ever reported. This is particularly distorting where no market insurance exists, such as in the case of nuclear power. Another element not addressed here in this report is technology <u>acceptance</u>. The European Commission’s Energy Roadmap (2011, p.65) emphasizes that the acceptance of a technology should ideally be considered in modeling energy markets.

In our own proposal of cost figures, all figures reflect a European perspective and they are expressed in 2010 EUR. Unless otherwise stated, a consistent exchange rate is applied to cost figures taken from literature: EUR-USD 1.33; EUR-GBP 0.83; EUR-NOK 7.39; EUR-AUD 1.4. A 9% discount rate is assumed, in line with EC roadmap. 2010 fuel prices (IEA 2011b) and a CO_2 price of 20 EUR/t are assumed when production costs are illustrated. In EUR/MWh, fuel costs figure at 3 for Uranium, 7 for biomass, 21.6 for gas (7.5 $/MBtu), 8.4

[3] As the EC Roadmap puts it: “Agents’ decisions about capital budgeting involve the concept of cost of capital, which is depending on the sector - weighted average cost of capital (for firms) or subjective discount rate (for individuals). In both cases, the rate used to discount future costs and revenues involves a risk premium which reflects business practices, various risk factors or even the perceived cost of lending. The discount rate for individuals also reflects an element of risk averseness.“ (EC 2011, p.73)

for coal (99 $/t) and 2.9 for lignite (10 $/t). Efficiency rates indicated in the proposal pertain to the most recent state-of-the-art technology.

2 Renewable Energy Technologies

2.1 Wind

Most of today's wind turbine systems use a 3-blade configuration with steel tower and nacelle built on a concrete foundation. Typical hub heights are around 100 meters for new onshore turbines (e.g. Enercon E-101) with rotor diameters around 50-100 m. Specific locations may require other hub heights and rotor geometries. According to DLR & SRU (2010), the average rotor diameter for onshore German locations is expected to raise to 116.7 m and hub height to 127 m with 4.4 MW rated power by 2030. For offshore turbines, a rotor diameter of 175 m at hub height of 128 m is expected in 2030, resulting in 10 MW rated output.

Several key characteristics of wind turbines are commonly used to compare performance. One of these is the power coefficient, which designates the energy conversion efficiency in dependence of wind speeds. In the future, the power coefficient is likely to remain comparable to today's systems, even though it depends on the rotor geometry. This is because the general shape of the power coefficient curves today is already close to the theoretical optimum, governed by Betz' law (Betz 1966). It is probable that new generations of wind turbines with enhanced rotor diameters will be constructed in a way to maintain these characteristics. Cut-in and cut-out wind speeds for typical wind turbines can be found in Hau (2008) and dena (2010). For onshore turbines cut-in wind speed at 4.5 m/s and rated wind speed at 12.5 m/s are widely used (dena 2010; Hau 2008). For offshore, 3.5 m/s cut-in wind speed and 12.5 m/s rated wind speed limits are common (dena 2010). In both cases, cut-out wind speeds are roughly 25 m/s, a wind speed level that is rarely attained in reality. In general, cut-in and cut-off power ratings can be flexibly tailored to specific needs of the geographical site, according to Hau (2008, p.594).

While most turbines use gears to transform kinetic energy into electricity, there are possibilities to construct gearless turbines. Such turbines with multi-pole generators generally require less maintenance since fragile bearings und dovetail connections are not used. Gearless turbines are less complex in design, but generators are heavier and of bigger size than their counterparts in turbines with gear. Today, approximately 10% of worldwide offshore turbines are gearless. Table 2 specifies that capital costs for offshore wind turbines lie between 1800 (close to shore) and 3000 (far) EUR/kW in 2010. Costs are likely to drop to 1425-2200 EUR/kW in 2030. For individual turbines, costs of around 1.687 million EUR are reported for a 1.5 MW system with gear in Hau (2008, p.812). An equally powerful system without gear is reported to cost 1.824 million EUR, the difference owing to adequate support structure to bear heavier stator and shaft.[4]

[4] According to Hau (2008, p.816), costs for turbines with gear can be attributed to the tower (28%), rotor blades (21%), electric systems (15%) and mechanic shaft and machines (36%). For gearless turbines, the share of cost components shifts from mechanic systems (18%) towards electric systems (37%) while tower (26%) and rotor blades keep about the same shares in total cost.

Onshore wind turbine systems can be considered as a relatively mature technology, thus learning rates are lower as compared to offshore systems. Capital cost figures at 1100-1300 EUR/kW in 2010 and fixed O&M cost lies at around 19-46 EUR/kW (IEA 2011b).

Offshore wind turbines exhibit higher construction and maintenance cost than onshore wind turbines with 76-182 EUR/kWa (IEA 2011b). Aggressive weather conditions such as turbulent winds, aggressive salt water, or the tides (North Sea) complicate the construction process and increase the need for maintenance. Technological lifetime of offshore turbines has not been tested in large-scale applications but is expected to be lower than the 20-25 years of onshore turbines. In the light of complicated maintenance on sea, gearless turbines can be particularly interesting for offshore installations. Due to broad experience with offshore wind power in the United Kingdom, a study of the UK Department of Energy and Climate Change can serve as good reference for cost estimations of offshore wind energy (Arup 2011).

The figures proposed in the end section in Table 33 are different from those used in the Energy Roadmap (EC 2011): this applies to offshore wind technology which undergo relatively little cost reductions in the Energy Roadmap (1796 EUR/kW in 2010, 1620 EUR/kW in 2050). We suggest taking 3000 EUR/kW as 2010 capital cost, which is a rough average of the sources mentioned in Table 2. A composition of costs for offshore wind systems is included in Table 3. When applying cost reduction rates from IEA projections (IEA 2010a), capital cost decreases to 2093 EUR/kW by 2050. Onshore wind turbine costs start with 1300 EUR/kW in 2010 and decrease towards 1075 EUR/kW by 2050 (see Table 33 for more information).[5]

Note that per unit capital cost expressed as EUR/kW needs careful interpretation in the context of wind power. Some industry experts expect per unit cost to rise in future as more powerful technologies (higher hub heights, turbine size, etc.) are likely to be deployed at locations with increasingly difficult accessibility. However, it is likely that higher capital cost will be overcompensated by higher full load hours in many instances. Molly (2012) indicates that the usual power installation of 400 W/m² does not lead to the most cost-effective power generation. Figure 2 illustrates that a lower specific power installation size would be optimal. A lower specific power installation with higher full load hours could also reduce the costs for grid connections due to lower capacities. In this context, the recent report of Agora (2013) comes to the conclusion that a capacity-oriented design of wind turbines increases the load factor of the grid and could so reduce system costs. The current legislation does not internalize these positive external effects.

[5] IEA (2010a) and Black & Veatch (2012) cite higher figures in the range of 1500 EUR/kW, but they do not include a cost degression over time.

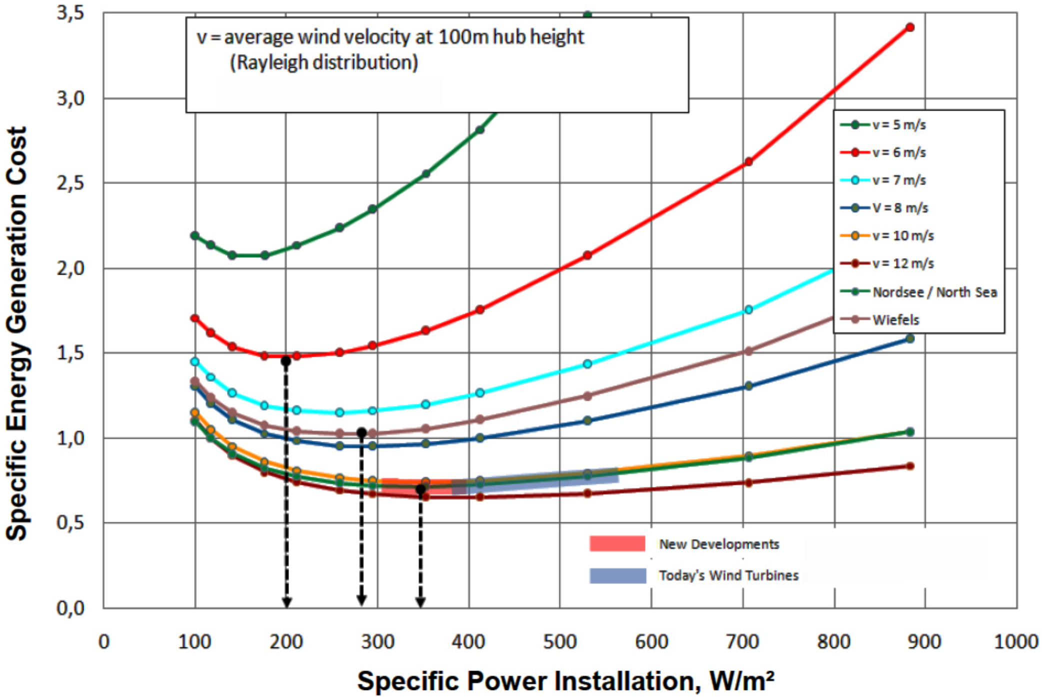

Figure 2: Generation cost and power installation for site-specific wind turbines.
Source: Adapted from Molly (2012)

	Capital cost in EUR/kW	2010	2015	2020	2025	2030	2035	2040	2045	2050
Onshore	(IEA 2011b)	1268	-	1223	-	-	1215	-	-	-
	(DLR & SRU 2010) table 9.3	1150	-	950	-	900	-	870	-	850
	(EWI et al. 2010)	-	-	1030	-	985	-	960	-	950
	(IRENA 2012) table 4.4	1028-1995								
	(VGB PowerTech 2011a)	1100-1300	-	-	-	1100	-	-	-	1100
	(WWF 2011) p.207	1200	-	800	-	700	-	600	-	600
	(Peter & Lehmann 2008)	1192	-	1063	-	986	-	-	-	-
	(Greenpeace 2010) p.55	-	941	749	-	714	-	680	-	671
	(Greenpeace 2012) p.64	-	1125	968	-	960	-	975	-	1013
	(DII 2012) p.43	1200	-	-	-	-	-	-	-	900
	(ECF 2010) Appendix A. p.3	1000-1300	-	-	-	900-1200	-	-	-	900-1200
Onshore, >5MW	(Arup 2011) table 6	1421-2184	1402-2154	1398-2149	1405-2160	1412-2172	-	-	-	-

Onshore, 50KW – 5MW	(Arup 2011) table 7	1409-2230	1390-2200	1386-2194	1393-2206	1400-2216	-	-	-	-
	(EC 2011) p.67	1106	-	1104	-	1085	-	-	-	1074
Offshore	(IEA 2011b)	2558	-	1778	-	-	1425	-	-	-
	(DLR & SRU 2010) table 9.4	3300	-	2100	-	1800	-	1500	-	1300
	(EWI et al. 2010)	-	-	2400	-	1670	-	1475	-	1350
	(IEA et al. 2010)	3737	-	-	-	-	-	-	-	-
	(VGB PowerTech 2011a)	2000-3000	-	-	-	1800-2200	-	-	-	1800-2200
	(EC 2011) p.67	1796	-	1789	-	1710	-	-	-	1620
	(WWF 2011) p.207	3000	-	1800	-	1500	-	1300	-	1200
	(Peter & Lehmann 2008)	1766	-	1389	-	1224	-	-	-	-
	(Greenpeace 2010) p.55	-	1650	1155	-	1095	-	998	-	979
	(Greenpeace 2012) p.64	-	3825	2850	-	2250	-	2025	-	1763
	(DII 2012) p.43	3000	-	-	-	-	-	-	-	1340-1920
	(ECF 2010) Appendix A, p.3	3000-3600	-	-	-	2000-2400	-	-	-	1900-2300
	(Crown Estate 2012) p.15, p.19	3133-3494	-	3253	-	-	-	-	-	-
Offshore, fixed-bottom	(Black & Veatch 2012) table 30	2489	2429	2368	2308	2248	2248	2248	2248	2248
Offshore, floating-platform	(Black & Veatch 2012) table 32	-	-	3158	3075	3000	3000	3000	3000	3000
Offshore, <100MW	(Arup 2011) table 13	1733 – 3007	1466 – 2545	1321 – 2292	1254 – 2176	1210 – 2100	-	-	-	-
Offshore, >100MW	(Arup 2011) table 14	2760 – 3820	2336 – 3233	2104 – 2911	1997 – 2764	1927 – 2666	-	-	-	-

	Variable O&M cost EUR/MWh	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Onshore	(IEA et al. 2010) table 3.7d	15-28	-	-	-	-	-	-	-	-
	(Wissel et al. 2008)	25-45	-	-	-	-	-	-	-	-
	(DLR & SRU 2010) table 9.3	0	-	0	-	0	-	0	-	0
	(IEA et al. 2010)	27-47	-	-	-	-	-	-	-	-
	(Black & Veatch 2012) table 28	0	0	0	0	0	0	0	0	0
	(ECF 2010) Appendix A, p.4	0	-	-	-	-	-	-	-	-

	Variable O&M cost EUR/MWh	2010	2015	2020	2025	2030	2035	2040	2045	2050
Offshore	(IEA et al. 2010) table 3.7d	25-40	-	-	-	-	-	-	-	-
	(Wissel et al. 2008)	40-65	-	-	-	-	-	-	-	-
	(DLR & SRU 2010) table 9.4	0	-	0	-	0	-	0	-	0
	(IEA et al. 2010)	34.7	-	-	-	-	-	-	-	-
	(ECF 2010) Appendix A, p.4	0	-	-	-	-	-	-	-	-
Offshore, fixed-bottom	(Black & Veatch 2012) table 30	0	0	0	0	0	0	0	0	0
Offshore, floating-platform	(Black & Veatch 2012) table 32	0	0	0	0	0	0	0	0	0

	Fixed O&M cost in EUR/kWa	2010	2015	2020	2025	2030	2035	2040	2045	2050
Onshore	(EWI et al. 2010)	-	-	41	-	39	-	38	-	38
Onshore	(IEA 2011b)	18.8	-	18	-	-	18	-	-	-
Onshore	(VGB PowerTech 2011a)	36.3 - 42.9	-	36.3	-	36.3	-	-	-	-
Onshore	(DLR & SRU 2010) table 9.3	46	-	38	-	36	-	34.8	-	34
Onshore	(DII 2012) p. 43	-	-	-	-	-	-	-	-	30
Onshore	(ECF 2010) Appendix A, p.4	20-25	-	-	-	-	-	-	-	-
Onshore	(Black & Veatch 2012) table 28	45.1	45.1	45.1	45.1	45.1	45.1	45.1	45.1	45.1
Onshore, >5MW	(Black & Veatch 2012) table 9	36- 88	36-89	37-90	37-91	38-92		-	-	-
Onshore, 0.05-5MW	(Arup 2011) tbl 10	47 - 84	47 – 85	48 – 86	48 – 88	49 - 89	-	-	-	-
Offshore	(EWI et al. 2010)	-	-	132	-	92	-	81	-	74
Offshore	(IEA 2011b)	76.5	-	53.3	-	-	42.8	-	-	-
Offshore	(VGB PowerTech 2011a)	86 -150	-	77 – 110	-	77 - 110	-	-	-	-
Offshore	(DLR & SRU 2010) table 9.4	181.5	-	115.5	-	99	-	82.5	-	71.5
Offshore	(IEA 2011b)	76.50	-	53.25	-	-	42.75	-	-	-
Offshore	(EWI et al. 2010)	-	-	132	-	92	-	81	-	74
Offshore	(VGB PowerTech 2011a)	86-150	-	-	-	77.4-110	-	-	-	77.4-110
Offshore	(DII 2012) p.43	-	-	-	-	-	-	-	-	54-76

Offshore	(ECF 2010) Appendix A, p.3	80-100	-	-	-	-	-	-	-	-
Offshore	(Crown Estate 2012) p.19 incl. transmission	196	-	161-166	-	-	-	-	-	-
Offshore, fixed-bottom	(Black & Veatch 2012) table 28	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2
Offshore, floating-platform	(Black & Veatch 2012) table 32	97.7	97.7	97.7	97.7	97.7	97.7	97.7	97.7	97.7
Offshore <100MW	(Arup 2011) table 18	120 – 320	112 – 187	208 – 179	104 – 174	102 – 172	-	-	-	-
Offshore >100MW	(Arup 2011) table 19	140 – 235	131 – 220	125 – 210	122 – 204	120 – 200	-	-	-	-

Table 2: Capital cost, fixed and variable O&M costs for wind turbines.
Source: Own compilation

Components in EUR/kW	**(Bruehl 2012) p. 23***	**(Douglas-Westwood 2012) p.15**
Turbine incl. Tower	1594	1610
Fundament incl. Transition piece	814	582
Transformer / Converter station	179	622
Cables inside park	106	-
Project Management (survey, planning, approval)	526	-
Allotment, transport, installation	184	473
Others and unpredicted difficulties	361	-
Total	**3764**	**3653**

Table 3: Capital cost components of offshore wind systems.
Source: Own compilation * *Source not confirmed*

2.2 Solar

Solar energy is typically transformed into electricity using either photovoltaic modules or concentrated solar power. Photovoltaic (PV) modules refer to the generation of electricity by utilizing the photovoltaic effect in semiconductor devices. Three sub-categories can be distinguished.

a) Crystalline silicon with sub-categories single-crystalline and polycrystalline. PV cells based on polycrystalline silicon can be produced with low energy input. Efficiency ranges at around 16% for devices on the mass market. PV cells based on mono-crystalline silicon exhibit high efficiencies of above 20%, but production of such wafer-based solar cells is more energy-intensive and expensive.
b) Thin films such as CdTe (cadmium-telluride), amorphous silicon, microcrystalline silicon or Copper Indium Gallium Selenide/Sulfide (CIGS). Among the thin-film material, amorphous silicon has the highest market share and exhibits efficiencies of up to 7%. It is notably used for weakly irradiated locations. Microcrystalline silicon reaches efficiency rates of 10%. CdTe cells are used in thin-film cells and feature efficiencies of 10% and more. CIGS solar cells are used in thin-film layers with efficiencies between 17 and 20%.
c) New technologies, organics and others. Organic solar cells (OSC) and dye sensitized solar cells (DSSC) have recently surpassed 12% laboratory efficiency. Despite promising progress regarding scale-up towards larger areas and increasing lifetimes, commercial maturity has not yet been reached. Other developments include quantum dot solar cells, casting wafers instead of sawing, concentrator modules and “Sliver” cells. Concentrator solar cells have been demonstrated to achieve efficiencies well over 40%, but are currently not on the mass market. Furthermore, building-integrated photovoltaics (BIPV) is an application with large commercial potential, but is currently considered a niche market. BIPV could possibly be a major market for window-integrated semi-transparent solar cell technologies, or for colorful façade-integrated devices.

Today, mono-crystalline PV cells dominate the market with 53% world market share while multi-crystalline panels represent a share of 35% and thin-film devices 12% (Rentzing 2012).

In addition to the choice of material, which determines the dominating semiconductor effects, several other factors affect the output performance of solar systems. The real power injection depends on the nominal installed capacity and the meteorological circumstances, namely the irradiation on the inclined panels and other losses and efficiency reductions that can be aggregated to a general performance ratio (PR) (Quaschning 2009). Solar trackers move PV cells to follow the sun and thus increase the performance ratio.

The efficiencies given above represent the module efficiencies of commercially available products. Laboratory devices in the R&D stage may have considerably higher power conversion efficiencies, but may need several years to reach market maturity. More details regarding the technological state of the art are shown in Figure 4.

Concentrated solar power (CSP) refers to the generation of electricity through process heat which is produced from the concentration of solar irradiation. Kazmerski (2007) distinguishes silicon-based and multi-injection CSP technology. The latter achieve higher power conversion efficiencies between 33 and 40%. Four CSP technologies are currently internationally promoted. Parabolic Trough Systems (1) are trough-shaped collectors which reflect sunlight onto a receiver pipe where oil is heated to power a steam turbine. The parabolically curved forms can also be replaced by segmented mirrors according to the principle of Fresnel (2). Both systems allow for a certain degree of hybridization and can be complemented with the use of fossil fuels at the steam turbine section. Power Towers (3) use sun-tracking mirrors (heliostats) to focus sunshine on a central receiver at the top of a tower. A Parabolic Dish System (4) consists of a parabolic-shaped dish that reflects solar radiation onto a central receiver mounted at the focal point.

Since solar power technologies are so diverse, most models only distinguish PV and CSP technology. It is then reasonable to take the most advanced PV technology as standard for the PV class and proceed likewise for CSP. Estimates for capital cost, fixed and variable O&M costs are shown in Table 4. Table 5 provides some indications on the composition of costs. Roughly 50% of the total cost of solar PV projects is due to the modules while mounting structures, inverters and cabling account for the rest; the exact percentage depends on the system size and capacity (IEA 2010a; Parsons Brinckerhoff 2012) Module costs depend on the price of commodities such as silicon (absorber) or silver (electrical contact), installation costs can be reduced on ground mounted locations compared to rooftops. It is noteworthy that installation costs have become more important in recent years due to sharply decreasing production costs. This has the consequence that thin-film technologies may have lower production costs than highly efficient mono-crystalline silicon solar cells, but suffer from high O&M costs due to the larger area that is required for the same power output. Solar CSP capital costs differ considerably between plants with or without storage and the size of the plant.

All in all, significant price reductions have characterized the PV market in recent years. While many studies from 2008-2012 assume capital cost figures in the order of 3000 EUR/kW and higher for modern PV systems, some more recent studies do reflect the latest developments and see capital costs as low as 1725 EUR/kW in 2015 including grid reinforcement cost (Greenpeace 2012) or 2200 EUR/kW for private (Arup 2011) and large-scale applications (IEA 2011b). Most recent data show that prices in Germany for PV < 10 kW in 2012 were below 1600 EUR/kW (Photon 2012a); the large-scale ground mounted PV project “Camp Astrid 2” with 650 kW, finalized and connected to the grid in December 2012, cost approximately 950 EUR/kW (Photon 2012b). Such data document significant price reductions and suggest that most of the current projections are too conservative.

Different studies have shown average price reductions of 15% per year since 2008 and a learning rate of PV modules about 20% (Wirth 2013; Pahle et al. 2012), corresponding to a decrease in PV module price per Wp of 20% per doubling of cumulative installed capacities. This learning rate has been observed, with slight temporary deviations, to be valid since about 1980, even though some specialists assume that price reductions may drop to 5% per year in the near future (Esau 2013). The learning rate on the system level has been determined to be about 14-18% (IEA 2000, p.11; IEA 2010b, p.18; Kersten et al. 2011).

The development of most recent and current world spot market net prices, as compiled from SolarServer (2013) and PVXchange (2013), is shown below; significant price reductions of up to 80% (depending on the type of technology) within 4 years are observed. A caveat in this context is that module spot market prices do not vary between industrialized countries with major markets; however, system prices can and do vary due to mainly “soft BoS” such as marketing or widely different approval procedures. An example is the difference of Germany and USA in 2011, which had been found by Seel et al. (2013) to be a factor of 2 (Germany: about 3.00 USD/Wp; USA: about 6.19 USD/Wp). Remote locations may also have higher costs due to transport requirements.

Currently, module costs dominate system prices with a share of about 50%, being in the range of 0.5 EUR/Wp (Hermle & Glunz 2013; Wirth 2013). The remaining costs consist of balance of system (BoS) costs such as expenses for cabling, framing, inverter, engineering, and construction labor costs. Further cost reductions for modules are likely; depending on the technology, prices below 0.4 EUR/Wp are expected, and novel approaches such as DSSC and OPV aim at well below 0.3 EUR/Wp. If efficiencies can be further increased, lower areas will be required per Wp, corresponding to lower BoS costs.

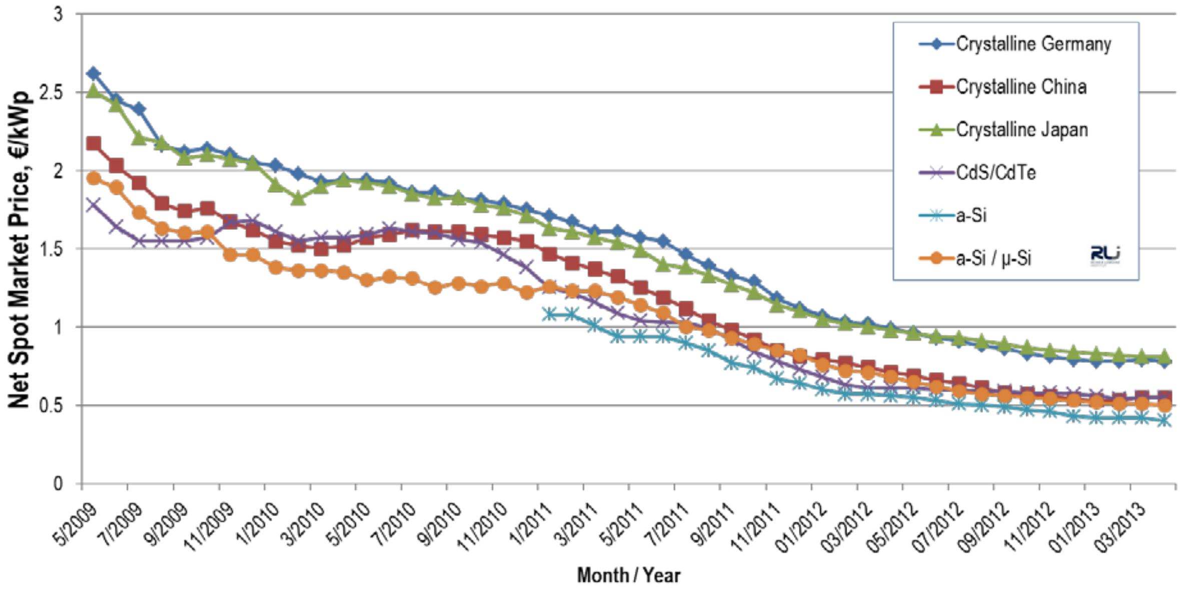

Figure 3: Net spot market module prices.

Source: Own composition based on SolarServer (2013) and PVXchange (2013)

In view of the dynamics of the market, we find that even the lower boundaries of the literature overview do not reflect the recent developments and are not suitable for future projections. If the industry achieves further price reductions due to scaling effects, lower material consumption and higher efficiencies, prices in the range of 750 EUR/Wp for ground mounted systems in 2020 seem plausible, assuming price reductions of only 3% per year. In this line of reasoning, the „BMU Leitstudie“ of DLR et al. (2012, p.211) anticipate a decrease of levelized production cost from roughly 280 EUR_{2009}/MWh in 2011 to 190 EUR_{2009}/MWh in 2015 and 65 EUR_{2009}/MWh in 2020.

We consider this estimate conservative; if the learning curve, which has been valid for over 30 years, will be valid in the future, prices in 2020 should be significantly lower. This is conceivable with a technological breakthrough such as successful market introduction of OPV with module costs of 0.2 EUR/Wp at close to 20% efficiencies, which might lead to system costs below 500 EUR/Wp. Since we do not recommend basing energy scenarios on such assumptions, we propose 750 EUR/Wp as system price in 2020 as suitable compromise on the conservative side.

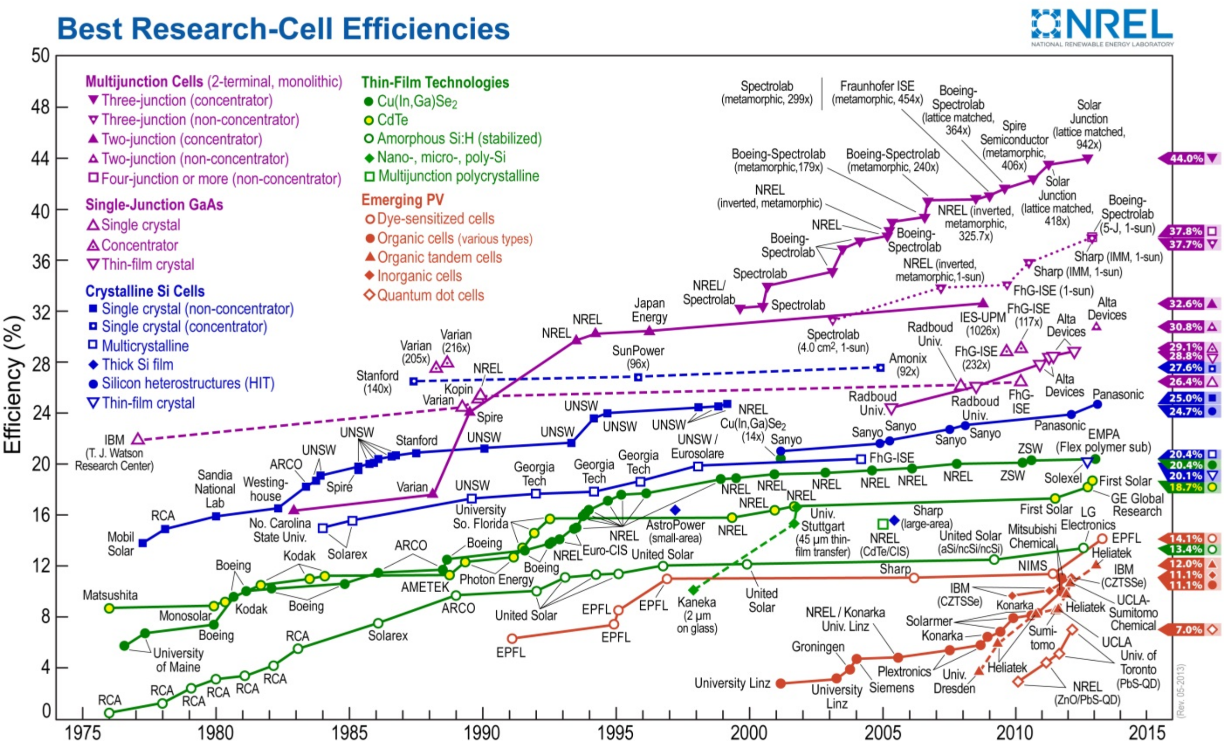

Figure 4: Efficiencies of solar technologies over time.

Source: Originally Kazmerski (2007) updated for 2013 [6]

CSP technologies have come under significant pressure in recent years due to the price reductions of PV. The learning rate per doubling of cumulated installed capacities is smaller with only 10-12% (Hernandez-Moro & Martinez-Duart 2012), and the global production has increased much more slowly. In 1984, global installed CSP capacities were about 14 MW and have increased until November 2012 to 2,230 MW (CSPWorld 2013; IRENA 2012); in contrast to that, PV has matured in the same time from 50 MW (1984) to 100,000 MW (2012). 18 CSP projects realized or under construction in 2010-2011 were reported to cost 5500-8500 USD_{2010}/kW, corresponding to about 4000-6000 EUR/kW (IRENA 2012). A comparison shows that such prices are in the upper range of the current literature. We propose as price projections for CSP without storage 4000 EUR/kWp in 2020, 3500 EUR/kW in 2030, 3000 EUR/kW in 2040 and saturation at 2500 €/kW in 2050. These numbers are all slightly above the median of the literature review and reflect current experiences and growth rates. A strong argument for market growth might be the good complementarity of CSP with heat storage (e.g., concrete, sand, or molten salts) and natural gas power plants for security of supply.

[6] Updated version from http://www.nrel.gov/ncpv/images/efficiency_chart.jpg

The graphic shows world-record laboratory solar cells with at least 1 cm² active area; the efficiencies were certified by independent laboratories.

	Capital cost in EUR/kW	2010	2015	2020	2025	2030	2035	2040	2045	2050
PV	(EWI et al. 2010) table 2.4.2-1	-	-	1375	-	1085	-	1015	-	1000
PV	(VGB PowerTech 2011a)	2600-3200	-	-	-	1700	-	-	-	1700
PV	(WWF 2011)	3300	-	1400	-	700	-	500	-	400
PV	(Peter & Lehmann 2008)	4477	-	2456	-	1884	-	-	-	-
PV	(Greenpeace 2010) p.55	-	1958	1332	-	770	-	589	-	571
PV	(Greenpeace 2012) p.63	-	1725	1238	-	960	-	780	-	795
PV	(EC 2011) p.67	4169	-	2678	-	1710	-	-	-	1366
PV	(Zweibel 2010) p.7529	2255	-	-	-	-	-	-	-	-
PV	(ECF 2010) Appendix A, p.3	2400-2700	-	-	-	1000-1400	-	-	-	800-1200
PV <10kW	(Seel et al. 2013) p.9	3195-5195	-	-	-	-	-	-	-	-
PV, <50kW	(Arup 2011) table 35	3278 – 6096	2959 – 4832	2077 – 3862	1781 – 3311	1604 – 2984	-	-	-	-
PV, >50kW	(Arup 2011) table 36	2248 – 4483	1782 – 3553	1424 – 2840	1220 – 2435	1100 – 2195	-	-	-	-
PV, open area	(DLR & SRU 2010) table 9.1	2470	-	1000	-	770	-	725	-	695
PV, open area	(IEA et al. 2010) table 3.7d, Germ.	2505	-	-	-	-	-	-	-	-
PV, large	(IEA 2011b)	2175	-	1695	-	-	1290	-	-	-
PV, large	(DII 2012) p.43	2100	-	-	-	-	-	-	-	700
PV, large	(Breyer & Gerlach 2012) table II	2400	-	970-1240	-	-	-	-	-	-
PV, base	(EWI 2012) table 8	3000	-	1796	-	1394	-	1261	-	1199
PV, building	(IEA 2011b)	2910	-	1928	-	-	1530	-	-	-
PV, roof	(Wissel et al. 2008) table 2.1	5200	-	-	-	-	-	-	-	-
PV, roof	(DLR & SRU 2010) table 9.1	3120	-	1430	-	1100	-	1030	-	985
PV, roof	(EWI 2012) table 8	3500	-	2096	-	1627	-	1471	-	1399
PV, roof	(IEA et al. 2010) table 3.7d, Germ.	2898	-	-	-	-	-	-	-	-
PV, roof	(Breyer & Gerlach 2012) table I	2700	-	1090-1400	-	-	-	-	-	-

	Capital cost in EUR/kW	2010	2015	2020	2025	2030	2035	2040	2045	2050
PV, amorphous	(Wagner 2004) table 11.16	5500-6500	-	-	-	-	-	-	-	-
PV, polycrystalline	(Wagner 2004) table 11.16	6550-7300	-	-	-	-	-	-	-	-
CSP	(IEA 2011b)	5370	-	3743	-	-	2813	-	-	-
CSP	(VGB PowerTech 2011a)	3000-3500	-	2000	-	-	2000	-	-	-
CSP	(WWF 2011) p.207	4400	-	3300	-	2500	-	2100	-	1900
CSP	(Peter & Lehmann 2008)	3978	-	3160	-	2667	-	-	-	-
CSP	(Greenpeace 2010) p.55	-	4182	3783	-	3197	-	3150	-	3120
CSP	(Greenpeace 2012) p.63	-	6075	4950	-	4313	-	3975	-	3600
CSP	(EC 2011) p.67	5562	-	4450	-	2959	-	-	-	1739
CSP, including storage	(ECF 2010) Appendix A, p.3	4000-6000	-	-	-	2900-3500	-	-	-	2200-2600
CSP, solar field	(DLR & SRU 2010) table 9.2, /kWel	1703	-	1078	-	817	-	726	-	681
CSP, power block	(DLR & SRU 2010) table 9.2	1150	-	1060	-	1006	-	985	-	971
CSP 7000m2, no storage	(EWI 2012)Table 8	3722	-	2220	-	1700	-	1400	-	1290
CSP, storage	(Black & Veatch 2012) table 27	5308	5112	4910	4451	3992	3534	3534	3534	3534
CSP, 8h storage	(DII 2012) p.43	6000	-	-	-	-	-	-	-	2000
CSP 11000 m^2, 20 MWh storage	(EWI 2012)Table 8	6794	-	3437	-	2300	-	2100	-	1963
CSP, no storage	(Black & Veatch 2012) table 26	3692	3549	3414	3271	3135	2998	2857	2722	2579
CSP 16000 m^2, 40 MWh storage	(EWI 2012)Table 8	10082	-	5500	-	3800	-	3100	-	2693

	Variable O&M cost in EUR/MWh	2010	2015	2020	2025	2030	2035	2040	2045	2050
PV, open field	(IEA et al. 2010) table 3.7d	22 - 40	-	-	-	-	-	-	-	-
PV, building	(IEA et al. 2010) table 3.7d	22 - 46	-	-	-	-	-	-	-	-
PV	(DLR & SRU 2010) table 9.1	0	-	0	-	0	-	0	-	0
PV	(Wagner 2004) table 11.16, 6% disc.	0	-	-	-	-	-	-	-	-
PV	(Zweibel 2010) p.7529	0	-	-	-	-	-	-	-	-
PV	(ECF 2010) Appendix A, p.4	0	-	-	-	-	-	-	-	-
CSP	(IEA et al. 2010) table 3.7d	20 - 27	-	-	-	-	-	-	-	-
CSP	(DLR & SRU 2010) table 9.2	0	-	0	-	0	-	0	-	0
CSP	(ECF 2010) Appendix A, p.4	0	-	-	-	-	-	-	-	-
CSP, storage	(Black & Veatch 2012) table 26	0	0	0	0	0	0	0	0	0
CSP, no storage	(Black & Veatch 2012) table 27	0	0	0	0	0	0	0	0	0

	Fixed O&M cost in EUR/kWa	2010	2015	2020	2025	2030	2035	2040	2045	2050
PV	(EWI et al. 2010) table 2.4.2-1	-	-	29	-	28	-	27	-	26
PV	(VGB PowerTech 2011a)	26-32	-	17	-	17	-	-	-	-
PV	(ECF 2010) Appendix A, p.3	20-25	-	-	-	-	-	-	-	-
PV open	(DLR & SRU 2010) table 9.1	25	-	10	-	8	-	7	-	7
PV	(Wagner 2004) table 11.16	0	-	-	-	-	-	-	-	-
PV	(Zweibel 2010)	11.3	-	-	-	-	-	-	-	-
PV, <50kW	(Arup 2011) table 38	20 - 85	20 - 85	20 - 85	20 - 85	20 – 85	-	-	-	-
PV, >50kW	(Arup 2011) table 39	32 - 19	32 - 19	32 - 19	32 - 19	32 - 19	-	-	-	-
PV, open field	(DLR and SRU, 2010) table 9.1	25	-	10	-	8	-	7	-	7
PV, large	(IEA 2011b)	33	-	25.5	-	-	19.5	-	-	-
PV,	(DII 2012) p. 43	-	-	-	-	-	-	-	-	19

	Fixed O&M cost in EUR/kWa	2010	2015	2020	2025	2030	2035	2040	2045	2050
large										
PV, large	(Breyer & Gerlach 2012) p.123	36	-	14.55-18.6	-	-	-	-	-	-
PV, building	(IEA 2011b)	43.5	-	29.3	-	23.3	-	-	-	-
PV, roof	(DLR & SRU 2010) table 9.1	16	-	7	-	6	-	5	-	5
PV, roof	(Breyer & Gerlach 2012) p.123	40.5	-	16.35-21						
CSP	(IEA 2011b)	214.5	-	150	-	104.3	-	-	-	-
CSP	(VGB PowerTech 2011a)	60-70	-	40	-	40	-	-	-	-
CSP, 8h storage	(DII 2012) p. 43	-	-	-	-	-	-	-	-	45
CSP, with storage	(ECF 2010) Appendix A, p.4	180-220	-	-	-	-	-	-	-	-
CSP, solar field	(DLR & SRU 2010) table 9.2	16	-	10	-	8	-	7	-	6
CSP, power block	(DLR & SRU 2010) table 9.2	29	-	27	-	25	-	25	-	24
CSP, storage	(DLR & SRU 2010) table 9.2	1.3	-	1.0	-	0.7	-	0.7	-	0.6
CSP, storage	(Black & Veatch 2012) table 26	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6
CSP, no storage	(Black & Veatch 2012) table 27	38	38	38	38	38	38	38	38	38

Table 4: Capital cost, fixed and variable O&M costs for solar PV and CSP systems.
Source: Own compilation

Components in EUR/kW	**(MacDonald 2011)**	**(Black & Veatch 2012)**
Project development	360	
Modules	1740	1053
Inverters	540	180
Installation (electrical and civil) works	360	
Balance of Plant (BoP)	420	139
Structures		609
Engineering, procurement, construction management services		41
Owner's cost		105
Total	**3420**	**2128**

Table 5: Capital cost components of PV systems.
Source: Own compilation

2.3 Biomass

Biomass use for electricity generation had a share of below 3% in EU-27 with approximately 100 TWh of production in 2011. Thus, biomass is the second largest source for non-intermittent renewable electricity in Europe (second only to hydropower). The Platts database (2011) reports 8.67 GW of capacity under construction or operating in the EU-27 in late 2011. That represents around 1% of total installed power plant capacity. 6.96 GW of the biomass plants are reported to use wood as basis and 0.53 GW use biogas. Abundant resources and favorable policies are reasons for a high concentration of biomass facilities in Northern Europe and the Alpine region (mostly co-generation from wood residuals).

Biomass fuel can come in many specifications as it encompasses diverse sources derived from timber, agriculture, food processing wastes or from fuel crops. It can also include sewage sludge and animal manure. At present times, most biomass power plants burn lumber, agricultural or construction wood residuals. IEA (2011b) distinguishes numerous possibilities for the use of biomass in electricity production: (1) “classic” biomass power plants, (2) biogas for distributed generation, (3) biomass co-firing in conventional power plants, (4) biomass waste incineration as well as (5) small and large-scale biomass CHP plants.[7]

Biomass co-firing in modern coal power plants reaches efficiency rates as high as 45%. It is the most cost-effective biomass use for power generation (IEA 2007). Further details can be found in the section on coal power plants.

Dedicated biomass plants and CHP are another form of biomass plants. Combustion power plants can burn the biomass fuel directly in boilers that supply steam for steam-electric generators. Due to feedstock availability issues, dedicated biomass plants for combined heat & power (CHP) are typically of smaller size and lower electrical efficiency compared to coal plants (30%-34% using dry biomass, and around 22% for municipal solid waste) according to IEA (2007). In cogeneration mode the total fuel efficiency may reach 85%-90% (IEA 2007).

With biomass gasification, biomass is converted into methane in order to fuel steam generators, combustion turbines, combined cycle technologies or fuel cells. IEA (2007) explains that the primary benefit of biomass gasification, compared to direct combustion, is that extracted gases can be used in a variety of power plant configurations. IEA (2007) suggests that biomass integrated gasification in gas-turbine plants (BIG/GT) is not yet commercially available, but integrated gasification combined cycle (IGCC) plants using black liquor (a by-product from the pulp & paper industry) are already in use (IEA 2007). Pilot projects with biomass gasification IGCC exist in Eggborough (8 MW, UK) and Värnamo (6 MW, SE).

[7] “In the short term, co-firing remains the most cost-effective use of biomass for power generation, along with small-scale, off-grid use. In the mid-long term, BIG/GT plants and biorefineries could expand significantly. IEA projections suggest that the biomass share in electricity production may increase from the current 1.3% to some 3%-5% (worldwide) by 2050, depending on assumptions. This is a small contribution compared to the estimated total biomass potential (10%-20% of primary energy supply by 2050), but biomass are also used for heat generation and to produce fuels for transport.” (IEA 2007, p.1)

Anaerobic digestion, landfill gas and waste incineration can be used to produce biogas, which can be used in conventional gas-fired power plants. Biogas use is expanding in small, off-grid applications.

Bio-refineries and hydrogen may open the door to combined, cost-effective production of bio-chemicals, electricity and biofuels (IEA 2007).

Because of the diversity of feedstocks and processes, costs of biomass-based power generation vary widely as shown in Table 6. Due to their small size, dedicated biomass power plants have higher capital costs than co-firing in coal power plants. Co-firing in coal power plants requires limited incremental investment (38-188 EUR/kW) and the electricity cost may be competitive if local feedstock is available at low cost (no transportation) (IEA 2007). Wood pellet prices are expected to rise from around 5 EUR/GJ in 2010 to around 10 EUR/GJ by 2020 (20 to 40 EUR/MWh) according to E4tech (2010, p.15) which raises power production costs from 50-100 EUR/MWh to around 125-250 EUR/MWh at typical efficiency rates of 20-40 % (US DoE 2012). The IPCC report reports an average efficiency of 32 % (Chapter 2 - 2011, p.216) and calculates electricity costs of 38-70 EUR_{2005}/MWh in cogeneration mode and 67-133 EUR_{2005}/MWh for wood pellet gasification (Chapter 2 - IPCC 2011, p.242).

	Capital cost in EUR/kW	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
General	(EWI et al. 2010) p.38	-	-	2300	-	2200	-	2125	-	2075
General	(VGB PowerTech 2011a)	2500	-	2500	-	2500	-	-	-	-
General	(Black & Veatch 2012) table 19	2880	2880	2880	2880	2880	2880	2880	2880	2880
General	(IEA 2011b) “Plant”	1778	-	1703	-	1598	-	-	-	-
General, dedicated	(ECF 2010) Appendix A, p.3	2300-2600	-	-	-	1600-1900	-	-	-	1300-1600
General, >50MW	(Arup 2011) table 43	2710-3361	2696–3344	2702–3353	2740–3398	2776–3444	-	-	-	-
General, <50MW	(Arup 2011) table 44	3128–4645	3113–4622	3120–4633	3162–4696	3205–4759	-	-	-	-
Cofiring	(IEA 2011b)	443	-	428	-	-	398	-	-	-
Cofiring	(Black & Veatch 2012) table 17	744	744	744	744	744	744	744	744	744
CHP medium	(IEA 2011b)	2753	-	2745	-	-	2543	-	-	-
CHP small	(IEA 2011b)	3968	-	3833	-	-	3555	-	-	-
Waste incineration	(IEA 2011b)	5483	-	5340	-	-	5288	-	-	-
Wood	(Wissel et al. 2008) Table 2.1	2100	-	-	-	-	-	-	-	-
Steam	(DLR & SRU 2010)	2500	-	2320	-	2150	-	2050	-	1950

	Capital cost in EUR/kW	2010	2015	2020	2025	2030	2035	2040	2045	2050
turbine	table 9.5									
Steam turbine, CHP	(DLR & SRU 2010) table 9.5	3930	-	3700	-	3600	-	3550	-	3530
Biogas	(IEA et al. 2010) table 3.7d: France, 5% discount	2015	-	-	-	-	-	-	-	-
Biogas	(Nagl et al. 2012) table 8	2400	-	2398	-	2395	-	2393	-	2390
Biogas, CHP	(DLR & SRU 2010) table 9.5	3420	-	3210	-	3110	-	3020	-	2980
Biogas, CHP	(Nagl et al. 2012) table 8	2600	-	2597	-	2595	-	2592	-	2590
Biogas, CHP	(IEA et al. 2010) table 3.7e – CH, 5% discount	8374	-	-	-	-	-	-	-	-
Biomass	(PIK et al. 2011)	883-2207	883-2207	883-2207	-	883-2207	-	883-2207	-	883-2207
Biomass	(Peter & Lehmann 2008)	4648	-	4295	-	4029	-	-	-	-
Biomass	(Greenpeace 2010)	-	1839	1840	-	1783	-	1762	-	1772
Biomass	Greenpeace (2012)	-	2325	2250	-	2100	-	2025	-	1987
Biomass solid	(Nagl et al. 2012) table 8	3300	-	3297	-	3293	-	3290	-	3287
Biomass solid	(IEA et al. 2010) table 3.7d: NL, 5% discount	3960	-	-	-	-	-	-	-	-
Biomass power (of CHP)	(Wagner 2004) table 11.19, 6%	2700-3000	-	3000	-	-	-	-	-	-
Biomass heat (of CHP)	(Wagner 2004) table 11.19, 6%	30-35	-	33-38.5	-	-	-	-	-	-
Biomass solid, CHP	(Nagl et al. 2012) table 8	3500	-	3497	-	3493	-	3490	-	3486

	Variable O&M cost in EUR/MWh	2010	2015	2020	2025	2030	2035	2040	2045	2050
General	(Black & Veatch 2012) table 19	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
General, dedicated without fuel	(ECF 2010) Appendix A, p.4	8-10	-	-	-	-	-	-	-	-
Fuel costs	(ECF 2010) Appendix A, p.4	45-55	-	-	-	-	-	-	-	-
Forest wood	(DLR & SRU 2010) table 9.5	32	-	42	-	45	-	45	-	45
Waste wood	(DLR & SRU 2010) table 9.5	6	-	7	-	8	-	9	-	10
Straw	(DLR & SRU 2010) table 9.5	32	-	42	-	45	-	45	-	45
Energy crops	(DLR & SRU 2010) table 9.5	42	-	52	-	55	-	55	-	55
Other biomass	(DLR & SRU 2010) table 9.5	6	-	7	-	8	-	8	-	10
Cofiring	(Black & Veatch 2012) table 17	0	0	0	0	0	0	0	0	0
Biogas	(IEA et al. 2010) table 3.7d: France	31	-	-	-	-	-	-	-	-
Biomass solid	(IEA et al. 2010) table 3.7d: NL	3.4	-	-	-	-	-	-	-	-
Biomass power (of CHP)	(Wagner 2004) table 11.19, 6%	0	-	0	-	-	-	-	-	-
Biomass heat (of CHP)	(Wagner 2004) table 11.19, 6%	0	-	0	-	-	-	-	-	-

	Fixed O&M cost in 2010 EUR/kWa	2010	2015	2020	2025	2030	2035	2040	2045	2050
General	(EWI et al. 2010) p.38	-	-	140	-	140	-	140	-	140
General	(VGB PowerTech 2011a)	62.5	-	-	-	62.5	-	-	-	62.5
General	(Black & Veatch 2012) table 19	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4
General, dedicated	(ECF 2010) Appendix A, p.4	13-15	-	-	-	-	-	-	-	-
General, <50MW	(Arup 2011) table 46	148 – 305	145 – 300	144 – 329	144 – 296	144 – 298	-	-	-	-
General >50MW	(Arup 2011) table 47	127 – 262	125 – 257	124 – 254	124 – 254	124 - 254	-	-	-	-
Cofiring	(IEA 2011b)	17.3	-	16.5	-	-	15.8	-	-	-

Cofiring	(Black & Veatch 2012) table 17	15	15	15	15	15	15	15	15	15
CHP medium	(IEA 2011b)	104	-	104	-	-	97	-	-	-
CHP small	(IEA 2011b)	151	-	146	-	-	135	-	-	-
Biomass (power of CHP)	(Wagner 2004) table 11.19, 6%	110	-	106	-	-	-	-	-	-
Waste incineration	(IEA 2011b)	209	-	203	-	-	189	-	-	-
Steam turbine	(DLR & SRU 2010) table 9.5	125	-	116	-	108	-	103	-	98
Steam turbine, CHP	(DLR & SRU 2010) table 9.5	267	-	252	-	245	-	241	-	240
Biogas, CHP	(DLR & SRU 2010) table 9.5	222	-	209	-	202	-	196	-	194
Biogas, CHP	(IEA et al. 2010) table 3.7e – CH	125	-	-	-	-	-	-	-	-

Table 6: Capital cost, fixed and variable O&M costs for biomass power systems.
Source: Own compilation

2.4 Geothermal

Large-scale geothermal stations in the EU-27 are located in Italy (Pomarance 60 MW, Montieri 40 MW, Monterotondo 40 MW, and numerous other locations (Platts 2011)) and planned or under construction in the United Kingdom (Redruth, 10 MW), Portugal (Ibeira Grande 14 MW, Geoterceira 12 MW), Germany (Munster-Bispingen 14.7 MW, Kirchweide 8 MW). For the EU-27, the Platts database reports an installed capacity of 950 MW. Among the power plant types, we distinguish three categories:

a) Dry steam plants use highly pressurized geothermal steam of 150 °C or greater to drive a conventional steam turbine. Almost all plants in Italy use this technology, even the most recent plants built in 2010 and 2011 (Chiusdino 20 MW, Radicondoli 20 MW) (Platts 2011). The world's largest geothermal facility at The Geysers in California is a dry steam plant as well.

b) Flash steam plants use tanks filled with high-pressure steam of 180 °C or greater and turbines are driven by released hot geothermal water that flashes into steam when released. On a world-wide scale, the flash steam power plant type is the most proliferated technology at present times due to its extensive use outside Europe (Iceland, USA, Philippines, Indonesia, Mexico). Within the EU-27, they are rarely used. One of the few examples is Sao Miguel in Portugal (3 MW).

c) Binary cycle plants are a recent development and they accept temperatures below 60 °C at pressure levels around 50 bar. A secondary fluid with low boiling point flash vaporizes upon heating by geothermal water. Materials for the secondary cycle are typically organic compounds such as Isobutane (Soultz, FR), isopentane or water-ammonia mixtures. Efficiency rates of 10-13% are reported for binary cycle plants. Examples of binary plants can be found in Germany (Mauerstetten 5.5 MW, Landau 3.8 MW, Unterhaching 3.4 MW) and France (Soultz, 1.5 MW) (Platts 2011).

Electricity generated from geothermal energy has an efficiency rate of 10-25% due to the relatively low temperature of geothermal fluids (typically less than 150 °C). Advantages of geothermal over other renewable energy sources include the high availability rates close to 100% and the ability to control dispatch.

Construction costs of power plant stations naturally depend on the depth of drilling. Geothermal wells are rarely deeper than 3 km at present times but there are projections of wells as deep as 10 km. Due to these significant differences, the range of capital costs is quite broad with 1800 EUR/kW to above 20000 EUR/kW across different studies. Detailed figures for the division of costs between power plant and well drilling can be found in EPRI (2010, p.10), where several technology types are distinguished. For conventional types of flash stream and binary cycle plants, power plant cost and well field cost contribute equally to the total costs according to IEA (2010a). Cost cuts due to technological progress are expected to be relatively modest, as can be seen in Table 32.

	Capital cost in EUR/kW	2010	2015	2020	2025	2030	2035	2040	2045	2050
General	(IEA 2011b)	1800 (!)	-	2708	-	-	2408	-	-	-
	(Wagner 2004) table 11.18, 6%	2000-3000	-	-	-	-	-	-	-	-
	(EC 2011) p.67	4203		4171	-	3839	-	-	-	3805
	(IEA et al. 2010) table 3.7d – Czech Rep, 5% discount	10659	-	-	-	-	-	-	-	-
	(EWI et al. 2010) p.38	-	-	10750	-	9500	-	9000	-	9000
	(EWI 2012) table 8	15000	-	10504	-	9500	-	9035	-	9026
	(EC 2011) p.67	4203		4171	-	3839	-	-	-	3805
	(PIK et al. 2011)	2649	2649	2649	-	2649	-	2649	-	2649
	(WWF 2011) p.207	3500	-	2700	-	2000	-	1600	-.	1500
	(Peter & Lehmann 2008)	5024	-	4754	-	4512	-	-	-	-
	(Greenpeace 2010)	-	8156	6888	-	5438	-	4532	-	3897
	Greenpeace (2012)	-	8325	6975	-	4800	-	3975	-	3412
	(Arup 2011) table 30	3720 - 9418		2389 - 6048	2351 – 5928	2298 – 5818	-	-	-	-
	(ECF 2010) Appendix A, p.3	2700-3300	-	-	-	2000-2400	-	-	-	1800-2200
	(Black & Veatch 2012) table 21	7444	7308	7237	7096	6955	6744	6606	6466	6331
2000m depth, EGS	(DLR & SRU 2010) table 9.6	8785	-	7178	-	6261	-	5986	-	5723
3000m depth, EGS	(DLR & SRU 2010) table 9.6	12031	-	9830	-	8574	-	8198	-	7838
4000m depth, EGS	(DLR & SRU 2010) table 9.6	15461	-	12632	-	11019	-	10535	-	10072
5000m depth, EGS	(DLR & SRU 2010) table 9.6	20637	-	16860	-	14707	-	14061	-	13442
2000m depth, CHP	(DLR & SRU 2010) table 9.7	10228	-	8356	-	7289	-	6969	-	6663
3000m depth, CHP	(DLR & SRU 2010) table 9.7	13474	-	11008	-	9603	-	9181	-	8777
4000m	(DLR & SRU	16904	-	13811	-	12047	-	11518	-	11012

depth, CHP	2010) table 9.7									
5000m depth, CHP	(DLR & SRU 2010) table 9.7	22079	-	18039	-	15736	-	15044	-	14383
Flash/Dry Steam	(EPRI 2010) table 1	1463-2250	-	-	-	975-1500	-	-	-	-
Binary Cycle	(EPRI 2010) table 1	1838-2850	-	-	-	1200-2025	-	-	-	-
Reversed Air Cond.	(EPRI 2010) table 1	1913-2625	-	-	-	1200-1875	-	-	-	-
EGS-Binary Cycle	(EPRI 2010) table 1	2250-6675	-	-	-	1350-3750	-	-	-	-
Hydrothermal	(Black & Veatch 2012) table 20	4466	4466	4466	4466	4466	4466	4466	4466	4466

	Variable O&M cost in EUR/MWh	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
General	(IEA et al. 2010) table 3.7d – Czech Rep.	14.3	-	-	-	-	-	-	-	-
General	(Wagner 2004) table 11.18, 6%	0	-	0	-	-	-	-	-	-
General	(Black & Veatch 2012) table 21	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3
General	(ECF 2010) Appendix A, p.4	0	-	-	-	-	-	-	-	-
General/ CHP	(DLR & SRU 2010) table 9.6/9.7	0	-	0	-	0	-	0	-	-
Hydrothermal	(Black & Veatch 2012) table 20	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3

	Fixed O&M cost in EUR/kWa	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
General	(EWI et al. 2010) p.38	-	-	380	-	360	-	340	-	320
General	(IEA 2011b)	48	-	54	-	-	48	-	-	-
General	(DLR & SRU 2010) table 9. Discounted with 6 %	29-69	-	24-57	-	21-49	-	20-47	-	19-45
General	(Wagner 2004) table 11.18	80.4	-	88.4	-	-	-	-	-	-
General	(Black & Veatch 2012) table 21	0	0	0	0	0	0	0	0	0
General	(Arup 2011) table 32	170 – 306	173 – 311	175 – 314	178 – 319	180 – 324	-	-	-	-
General	(ECF 2010) Appendix A, p.4	90-110	-	-	-	-	-	-	-	-
CHP	(DLR & SRU 2010) table 9.7	34-74	-	28-60	-	24-53	-	23-50	-	22-48
Hydrothermal	(Black & Veatch 2012) table 20	0	0	0	0	0	0	0	0	0

Table 7: Capital cost, fixed and variable O&M costs for geothermal power systems.
Source: Own compilation

2.5 Hydro

At present, hydropower is the largest source of renewable electricity. 153.3 GW installed hydro capacity are operating or under construction in the EU-27 as of late 2011 (Platts 2011). 40.9 GW thereof are pump storage facilities. Important hydroelectric power sources outside the EU-27 but with direct relevance for European markets are located in Switzerland and Norway. Hydropower stations are usually categorized into run-of-river (RoR), reservoir and pump storage (PS) facilities. Capital costs for hydroelectric plants are highly case-specific, since many local conditions must be reflected. The round-trip efficiency of pump storage is typically around 75%.

Table 8 shows that hydro electricity plants are a relatively mature technology where little cost reductions are expected. Economies of scale due to mass production are not observed; however, large hydro plants typically have lower unit costs than smaller sized plants. Hydropower is divided into large and small systems with the cut-off point between 10 MW and 50 MW, depending on the country (IEA 2010a). Small systems are usually RoR designs. Larger systems include reservoirs and pump storage facilities, which are less benign to the environment due to their size and therefore more controversial. Capital costs for hydraulic power plants with storage (pump storage or reservoir) not only depend on the size of the power conversion facility but also on the size of the attached storage. In Germany, the size of a hydro storage (in MWh) is on average around 7-8 times that of the conversion unit power rating (MW) (DLR & SRU 2010; Schill & Kemfert 2011). Hence, a storage lake would be depleted after 7-8 hours under full operation. The average MWh/MW ratio can be used to convert storage investment cost and fixed O&M cost from EUR/kWh to EUR/kW.

	Capital cost in EUR/kW	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
RoR	(EWI 2012) table 8	4500	-	4500	-	4500	-	4500	-	4500
RoR	(Wissel et al. 2008) table 2.1	4982	-	-	-	-	-	-	-	-
RoR	(VGB PowerTech 2011a)	1800	-	-	-	1800	-	-	-	1800
RoR repowered	(DLR & SRU 2010) table 9.9	1446	-	1537	-	1557	-	1557	-	1565
RoR new	(DLR & SRU 2010) table 9.10	4946	-	5037	-	5057	-	5057	-	5065
Reservoir repowered	(DLR & SRU 2010) table 9.12	1446	-	1537	-	1557	-	1557	-	1565
PS	(DLR & SRU 2010) table 9.14 (converter)	1600	-	1600	-	1600	-	1600	-	1600
PS	(EWI 2012)	850	-	-	-	-	-	-	-	-
PS	(DII 2012) p.40	-	-	-	-	-	-	-	-	1000
Large scale	(EWI et al. 2010) p.38	-	-	3850	-	4180	-	4950	-	5500

	Capital cost in EUR/kW	2010	2015	2020	2025	2030	2035	2040	2045	2050
General	(WWF 2011) p.207	2500	-	2500	-	2500	-	2500	-	2500
General	(Greenpeace 2010)	-	2148	2214	-	2314	-	2397	-	2471
General	(Greenpeace 2012)	-	2550	2625	-	2738	-	2625	-	2925
General	(Wagner 2004) table 11.17, 6%	1130-2500	-	1243-2750	-	-	-	-	-	-
General	(Black & Veatch 2012) table 22	2632	2632	2632	2632	2632	2632	2632	2632	2632
General	(Arup 2011) table 23	3356 – 11408	3407 – 11579	3457 – 11750	3509 – 11926	3560 - 12103	-	-	-	-
General	(ECF 2010) Appendix A, p.3	1800-2200	-	-	-	1750-2000	-	-	-	1500-1900
Large scale	(IEA 2011b)	1673	-	1920	-	-	2228	-	-	-
Large scale	(IEA et al. 2010) table 3.7d, 5% discount	2886-15977	-	-	-	-	-	-	-	-
Small-sized	(EWI et al. 2010) p.38	-	-	2750	-	2970	-	3080	-	3190
Small-sized	(IEA 2011b)	2925	-	2925	-	-	2963	-	-	-
Small-sized	(IEA et al. 2010) table 3.7d, 5% discount	3374-9689	-	-	-	-	-	-	-	-

	Variable O&M cost in EUR/MWh	2010	2015	2020	2025	2030	2035	2040	2045	2050
RoR	(DLR & SRU 2010) table 9.9	0	-	0	-	0	-	0	-	0
Reservoir	(DLR & SRU 2010) table 9.12	0	-	0	-	0	-	0	-	0
PS	(DLR & SRU 2010) table 9.14 (only converter + 10 €/MWh for storage)	0+10	-	0+10	-	0+10	-	0+10	-	0+10
General	(Black & Veatch 2012) table 22	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
General	(ECF 2010) Appendix A, p.3	0	-	-	-	-	-	-	-	-

	Fixed O&M cost in EUR/kWa	2010	2015	2020	2025	2030	2035	2040	2045	2050
RoR & Reservoir	(DLR & SRU 2010) table 9.9-14 discounted with 6%	22.4	-	22.8	-	22.9	-	22.9	-	22.9
RoR	(VGB PowerTech 2011a)	18	-	-	-	18	-	-	-	18
PS	(VGB PowerTech 2011a)	11-24	-	-	-	11-24	-	-	-	11-24
PS	(DLR & SRU 2010) table 9.14 (only converter)	16	-	16	-	16	-	16	-	16
PS	(DII 2012) p.40	-	-	-	-	-	-	-	-	20
General	(Wagner 2004) table 11.17, 6%	58-93	-	61-99	-	-	-	-	-	-
General	(Black & Veatch 2012) table 22	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
General	(Arup 2011) table 25	25.2 – 138	25.2 – 140	26.4 – 143	26.4 - 145	27.6 - 149	-	-	-	-
General	(ECF 2010) Appendix A, p.4	5-10	-	-	-	-	-	-	-	-
Large scale	(IEA 2011b)	42	-	48	-	-	55.5	-	-	-
Small-sized	(IEA 2011b)	66.8	-	75	-	-	57.8	-	-	-

Table 8: Capital cost, fixed and variable O&M costs for hydro power systems.
Source: Own compilation

2.6 Wave and Tidal

243 MW of installed capacity of tidal energy facilities are either operating or under construction in the EU-27 as of late 2011. The dominant share of 240 MW lies in France, off the English Channel coast at La Richardais. There is 3.75 MW installed capacity of wave energy power plants in the EU-27 either operating or under construction. 2.8 MW thereof lies in Scotland, where the Orkney Islands are an important location. All wave energy plants are of recent type, i.e. built after 2000. According to the IEA Technology Perspectives Report (2010a), there is a "wide variety of methods for extracting energy associated with ocean waves, including oscillating water column systems, absorber systems (point, multipoint and linear) or overtopping devices. These devices and systems use different techniques for 'capturing' the wave energy and employ a variety of different methods for converting it to electricity" (IEA 2010a). Investments cost for the different wave and tidal power plants are estimated to be up to 5000 EUR/kW in 2010. The IEA World Energy Outlook (2011b) projects cost reductions in the order of 50% by 2035. Cost cuts of more than 75% are projected by the IPCC (2011, chap.6).

	Capital cost in EUR/kW	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Marine	(IEA 2011b)	5040	-	4178	-	-	2685	-	-	-
Wave	(IEA et al. 2010) table 3.7d – Sweden 5% disc.	2694	-	-	-	-	-	-	-	-
Wave	(Black & Veatch 2012) table 23	-	6947	5233	4286	3556	2970	2571	3008	4008[8]
Wave	(WWF 2011) p.207	3600	-	2800	-	2300	-	1800	-	1600
Wave	(IPCC 2011) p.523 2005 EUR/kW	4651 – 12078	-	-	-	-	-	-	-	-
Ocean	(IPCC 2011) p.523 2005 EUR/kW	3376 – 10782	-	-	-	-	-	-	-	-
Tidal	(IPCC 2011) p.523 2005 EUR/kW	3151 – 9227	-	-	-	-	-	-	-	-
Tidal	(Black & Veatch 2012) table 24	-	-	3278	2602	2429	-	-	-	-
Tidal barrage	(IEA 2010a) p.134	2250-3750	-	-	-	-	-	-	-	1500-1840

	Variable O&M cost in 2010 EUR/MWh	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Wave	(IEA et al. 2010) table 3.7d – Sweden 5% disc.	56.9	-	-	-	-	-	-	-	-

	Fixed O&M cost in	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**

[8] The cost increase after 2040 reflects the use of lower quality sources.

	EUR/kWa									
Marine	(IEA 2011b)	152	-	126	-	-	80	-	-	-
Wave	(Black & Veatch 2012) table 23	-	356	268	220	183	153	132	156	205[9]
Wave	(IPCC 2011) p.523 2005 EUR/kWa	135	-	-	-	-	-	-	-	-
Tidal	(IPCC 2011) p.523 2005 EUR/kWa	75-105	-	-	-	-	-	-	-	-
Tidal	(Black & Veatch 2012) table 24	-	-	111	88	84	84	84	84	84
Tidal barrage	(IEA 2010a) p.134	90	-	-	-	-	-	-	-	50

Table 9: Capital cost, fixed and variable O&M costs for marine power systems.
Source: Own compilation

[9] The cost increase after 2040 reflects the use of lower quality sources.

3 Conventional Technologies

3.1 Nuclear

In early 2012, 139 nuclear reactor units were in commercial operation in the EU-27, providing around 126 GW of capacity (European Nuclear Society 2012). Worldwide, a total of 429 operating reactors combine an installed capacity of 364 GWe as of July 2012, producing a share of electricity of around 11% (Schneider et al. 2012, p.8). Nuclear power reactor types are characterized by the choice of a neutron moderator and cooling medium, which leads to different fuel designs (IEA et al. 2010). According to IEA et al. (2010), more than 88% of the commercial reactors currently in operation worldwide are cooled and moderated by light (ordinary) water. The two major types of light water reactors are pressurized water reactors (PWRs) and boiling water reactors (BWRs). About 7% of the installed capacity in the world use heavy water (deuterium oxide) as coolant and moderator, with the remaining reactors in operation being based on various other designs. It is generally acknowledged that nuclear power plant technologies can be categorized into four generation types:

- Early prototype reactors of the <u>1st generation</u> are not considered in the analysis here for they are outdated.
- Most of today's reactors in Europe can be considered as <u>2nd generation</u> type commercial power reactors. The second generation also includes the Canadian CANDU reactor and the Soviet pressurized water VVER/RBMK reactor types, both widely deployed since the mid-1960s.
- <u>3rd generation</u> reactors are characterized by evolutionary designs with improved safety compared to their preceding generation. The 3rd generation includes state-of-the-art reactors such as the Evolutionary Pressurized Water Reactor (EPR) developed by AREVA/SIEMENS (under construction in Olkiluoto (FI), Taishan (CN) and Flamanville (FR)), the Advanced Boiling Water Reactor ABWR of Hitachi-GE (originally planned in Visaginas (LT)) and the AP-1000 PWR of Westinghouse (planned for Vogtle (USA)).
- <u>4th generation</u> reactors are considered to provide enhanced safety through proliferation-resistance and minimal waste production. These reactor types are partly based on fundamentally different technological concepts such as fusion technology (under construction in Caderache (FR)) or the use of alternative fuels (Thorium in research reactors in Juelich and formerly Hamm (DE)). However, deployment for commercial construction seems far from certain. Many experts believe that fourth generation reactor types are unlikely to be readily available and competitive anytime soon (Economist 2012; IEA 2010a).

A compilation of different construction cost estimates is shown in Table 10. Since there have been virtually no new completed constructions of nuclear power plants in the European Union since Civeaux-II (FR) in 1991 (Schneider et al. 2012, p.70), construction cost estimates are difficult to obtain. Current experience from France and Finland confirms traditional wisdom that planned cost figures are regularly overrun, while China provides a counter-example. Cooper (2009) shows how cost figures quoted in the literature have increased over the last two decades which points to high cost uncertainty (see Figure 4). For Olkiluoto and Flamanville, overnight construction cost escalated from reported 1500 EUR/kW in 2006 over 4500 EUR/kW in mid-2008 (Thomas 2010b) to above 5100 EUR/kW in December 2012 (EnergyMarketPrice 2012). The high cost overruns may be due to higher one-of-a-kind effects (first construction of EPR reactors), but have also been attributed to the inherent nature of nuclear power which requires the most precautious safety standards for construction materials and automated control systems. It seems that the automated control systems have been a reason for cost overruns in the case of Olkiluoto (Reuters 2012). In line with this, Schneider et al. (2012, p.34) indicate that project planners of the Hinkley Point (UK) nuclear power station count with capital costs of around 5400 EUR/kW.

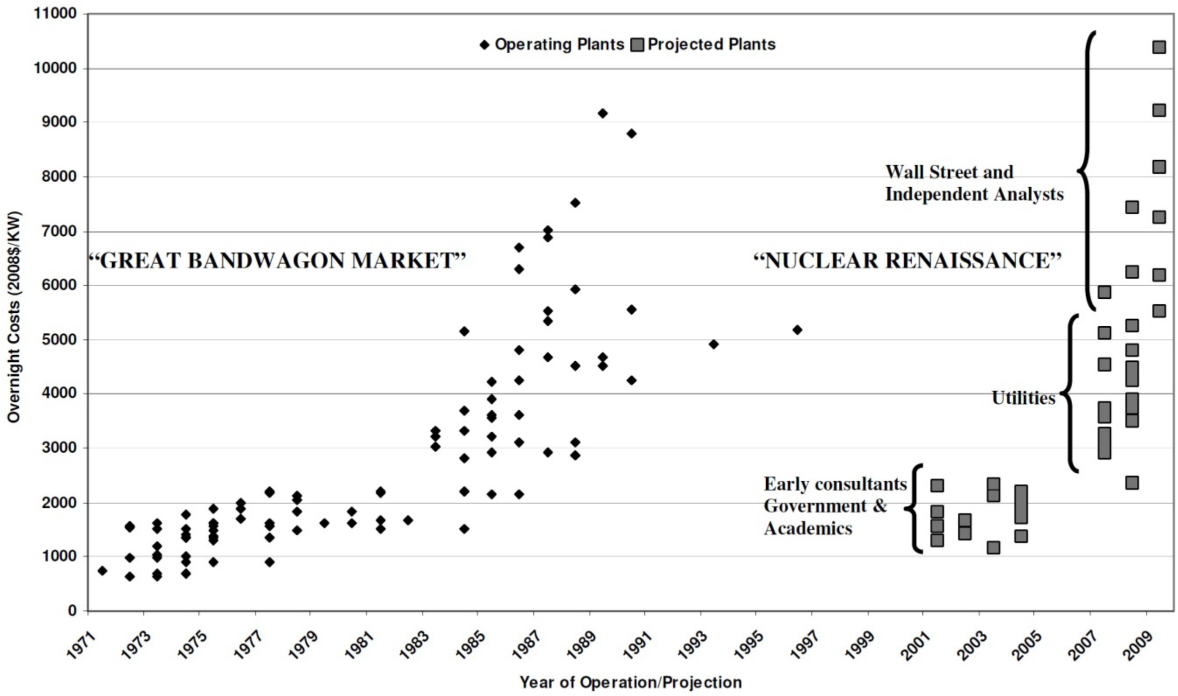

Figure 4: Evolution of cost estimates for nuclear power plants.

Source: Adapted from Cooper (2009)

Many cost figures in the literature omit costs of waste disposal, decommissioning[10] and insurance, or external costs. A screening of the relevant literature suggests that construction costs of 4000-5000 EUR/kW are plausible for third generation nuclear power plants. Additionally, one must also consider decommissioning (decontamination, deconstruction cost and operation cost after closure) as part of the capital cost. Capital cost then increases by 300-800 EUR/kW (Meyer 2012). Meyer (2012, p.44) proposes to add a risk premium of another ca. 400 EUR/kW to account for unexpected cost overruns of decommissioning. If all future costs for waste disposal (temporary storage, storage material, transport, re-processing, ultimate disposal and stockpile site exploration) are reflected in the fixed cost

[10] There are three generally accepted approaches to decommissioning: Immediate dismantling, deferred dismantling and entombment (Samseth et al. 2012). Cost figures can vary greatly depending on the chosen type of decommissioning.

part, capital cost rises by further 1000-1200 EUR/kW. Hence, all aspects included, a capital cost estimate with fixed operation cost of around 6000 EUR/kW is reasonable. Since no positive learning curves have been observed in nuclear power plants thus far (Grubler 2010; Rangel & Leveque 2012), we suggest to keep this figure constant for the future.

Variable generation cost figures at around 15-25 EUR/MWh in most studies, depending on the fuel cost, plant efficiency, operation and maintenance cost. Again, most studies ignore insurance and waste disposal costs. Insurance against accidents would increase the cost of nuclear power generation to up to 560 EUR/MWh (Guenther 2011). Due to such exorbitant costs, no full insurance policy for nuclear power plants has ever been contracted (see Diekmann (2011) for an overview). The European Commission is expected to propose rules on liability of nuclear plants in 2013. In any event, if the costs of potential accidents were included in the cost figures for nuclear plants, the production of nuclear power would not be economic at all.

Most numbers given in the tables below therefore do not incorporate the significant risk premiums that should be considered when investigating the operation and construction of nuclear power plants. Meyer (2012) and EnergyFair (2012) recognize the risk underlying investment decisions into nuclear power plants. These risks include not only market risks (common to all power plant types) but also substantial policy, subsidy and cost risks which are significantly higher for nuclear power as compared to other power generation technologies.

All costs in EUR/kW	**Construction (2010 EUR/kW)**	**Decommission (2010 EUR/kW)**	**Waste Fixed (2010 EUR/kW)**	**All-in (2010 EUR/kW)**
(IEA et al. 2010) p.48	4400 (CH) 2900 (FR)	15% of construction cost ~ 440-660	-	+ contingency cost 15% of capital cost ~ 3780-5720
(IEA 2011b) p.456	3010 (EU)	-	-	-
(EC 2011)	4382	-	-	-
(Capros 2011)	4057	-	-	-
(Lazard 2008)	3570	-	-	5130
(DOE 2008)	-	-	-	4436
(Severance 2009)	2765	-	-	7171
(VGB PowerTech 2011a)	3000	-	-	-
(Black & Veatch 2012) table 1	-	-	-	4684
(ECF 2010) Appendix A, p.3	2700-3300	-	-	-
(OECD & NEA 2003)	-	120 (PWR) 116 (VVER) 325 (BWR)	-	-
(Zweibel 2010) p.7529	4500	-	-	-
(Prognos 2008)	-	362	-	-
(RWI 1997) p. 14	2834	-	-	-

(CNIC 2007)	-	337 (PWR) 372 (BWR)	-	-
(Song 2011)	-	345	-	-
(Samseth et al. 2012)	-	10-15% of construction cost	-	-
(Thomas 2010a)		10% of construction cost		
(Meyer 2012) p.44	-	~ 800	~ 700	
(Jackson Consulting 2010)	-	-	1044 (EPR) 1179 (AP1000)	-
(SwissNuclear 2011)	-	-	1021 (average)	-

Table 10: Capital cost estimates for 3rd generation nuclear power plants.
Source: Own compilation. Figures are rounded

Component (EUR/MWh)*	**MacDonald (2011)**	**Black & Veatch (2012)**
Site preparation and licensing	390	
Reactor island	1200	575
Turbine island	270	226
Fuel pathway	300	
Civil works	1680	
Yard/Cooling/Installation		2780
Electrical works	150	
Balance of plant	210	
Engineering, Procurement, Construction Management		729
Owners Cost		876
Total	**4200**	**4586**

* Excludes costs of decommissioning, waste management and insurance.

Table 11: Capital Cost components for nuclear power plants.
Source: Own compilation

All costs in EUR/MWh	O&M		Fuel	External		Variable production cost
	Fixed	Variable		Waste	Insurance	
(NEI 2010)	10.70		4.70	0	0	15.40
(IEA et al. 2010)	11.10		7.03	-	-	18.13 (own calculation)
(EIA 2011)	7.97	8.40		-	-	16.37 (own calculation)
(MacDonald 2010)	13.74	2.37	5.97	2.37	-	24.45 (own calculation)
(Ristö & Kivistö 2008)	5.00	5.00	5.00	-	-	15.00 (own calculation)
(ECF 2010) Appendix A, p.4	90-110	0	7.0-9.0	-	-	
(Matsuo et al. 2011)	24.32		5.40	2.70	-	32.42 (own calculation)
(Guenther 2011)	-	-	-	-	560.00	-
(CdC 2012)	13.84		5.23	-	-	21.95 (includes taxes of 2.88)
(Prognos 2008)	8.00 (without maintenance)		8.70			16.70 (own calculation)
(JAEC 2011)	-		-	18.28	14.41	-
(Jackson Consulting 2010)	-		-	2.14	-	-
(VGB PowerTech 2011a)	60 EUR/kWa		-	-	-	< 18
(RET 2013)	102 EUR/kWa	4.3	2.4 - 7	-	-	ca. 11

Table 12: Electricity production cost for 3rd generation nuclear power plants.
Source: Own compilation

3.2 Coal

Pulverized coal-fired power plants can best be distinguished by fuel (sub-bituminous/lignite or bituminous/coal) as well as by thermodynamic characteristics (operating temperature and pressure levels). A common classification is made based on the criticality of boilers.

- Subcritical pulverized-coal firing is used in conventional power plants which employ boiler operating pressures below 221 bar and efficiencies in the order of 30-40%.
- Supercritical describes the state of a substance where the liquid and the gaseous phase are a homogenous fluid. Water reaches this state at a pressure level above 221 bar (22.1 MPa) and 374 °C (Siemens 2008; EPA 2010). Above an operating pressure of 221 bar in the evaporator part of the boiler, the steam cycle is called supercritical. Typical supercritical boilers operate at temperature levels of 570-590 °C and pressure levels of around 240 bar which translates into efficiency levels of around 41-45% (EPA 2010).
- Ultra-supercritical power plants increase these limits up to 700 °C and 350 bar with the help of more resilient boiler and by-pass valve material, for instance nickel-based alloys, ferritics or austenitics (iron-based alloys) with new coatings instead of chrome steel (Singheiser 2009). The higher temperature and pressure levels make higher efficiency rates of 50% and more possible (Siemens 2008).

New coal-fired power plants expose greenfield capital cost ranging from 1200 (subcritical) to 2100 EUR/kW (ultra-supercritical). These costs include all cost components, most prominently plant material costs (metals i.e. notably steel, cement, concrete, stone, gravel) and labor cost for initial construction and final decommissioning. A literature survey with more detailed cost figures is given in Table 13.

The use of an Integrated Gasification Combined Cycle (IGCC) can be thought of as alternative concept to an ultra-supercritical boiler. Here, a thermo-chemical reaction with oxygen and steam is used to convert liquid or solid fossil fuels (e.g. hard coal) into a synthesis gas mixture of carbon monoxide (CO), hydrogen (H_2), and carbon dioxide (CO_2), along with small amounts of hydrogen sulphide (H_2S). After cleaning, the purified syngas is fired in a combustion turbine to generate electricity. The exhaust gas is used to produce superheated steam (in the heat recovery steam generator) that drives a steam turbine and generates further electricity. Overnight construction costs for IGCC plants are estimated in the order of 2000 EUR/kW (Table 13). The technology is not considered to be commercially viable in 2012. Only a hand full of coal-based IGCC pilot plants (dry-fed and slurry-fed) have been built in Europe [Vresova (400 MW Lignite, CZ), Schwarze Pumpe (40-75 MW Lignite, DE), Buggenum (250 MW Coal, NL), Puertollano (350 MW Coal, ES)]. However, learning effects may reduce costs and increase competitiveness in the near future. Accordingly, there are plans to build IGCC plants for instance in the UK (Teesside, Hatfield, Killingholme). In total, 2620 MW of IGCC installed capacity (65% Oil and 35% Coal) are located in Europe, 1120 MW (71% Oil, 29% Coal) are installed in Asia and Australia and 2020 MW (17% Oil, 83% Coal) in North America in 2009 (Karg 2009). Hence, a great share of existing gasification power plants is not coal-based.

A lignite-fired power plant with optimized plant engineering (known as “Braunkohlekraftwerk mit optimierter Anlagetechnik”, BoA) is a recent technology featuring efficiency rates up to 43.2% (RWE 2005). The increase in the efficiency results from the combination of improved turbine blade design, boiler material which allows for greater temperature and pressure levels (580/600 °C and ca. 260 bar) as well as flue gas heat recovery for pre-heating of combustion air and steam-water cycle. BoA plants typically use circulating fluidized bed combustion (FB) technology for the dehydration of combustibles in order to enhance efficiency rates. In pulverizing and drying units of conventional plants, lignite - which contains over 50% water - is dried at temperatures of 1000 °C. Temperature requirements can be reduced by about 100 °C with FB. [11] Additionally, the heat of steam used in fluidized beds can be recovered and re-used in other processes (Klutz et al. 2010). In Niederaussem (DE) a lignite-fired power plant with BoA and FB technology has been in operation since 2003. Two similar lignite-fired power plants went online at Neurath (DE) in summer 2012. Based on the BoA technology, an improved BoAplus power plant concept includes the drying of fuel prior to the combustion process which is expected to allow for higher efficiency rates above 45%, as planned for Niederaussem (DE). Literature estimates capital costs for new-built lignite power plants to range from 1400 EUR/kW to 2680 EUR/kW.

An alternative to newly constructed power plants is partial refurbishment, also known as retrofitting. It is common practice in the power sector to extend the lifetime of retiring power plants by replacing several key components such as turbines or boiler while keeping in place all other parts. The cost for retrofitting power plants is highly case-specific. RWE (2009) reports a cost for lignite-fired plants in a range from 1000 EUR/kW for Neurath (DE) to 1140 EUR/kW for Niederaussem (DE). During the consultation phase of this report, it was reported that lower retrofitting costs for lignite power plants in the range of 50-200 EUR/kW are observed. The costs for retrofits of coal-fired power plants are reported to be between 800 EUR/kW for Farge (DE) (EOn 2005) and 1785 EUR/kW for Ibbenbueren (DE) (RWE 2009). According to RWE (2009), costs for environmental upgrades with flue gas desulphurization and improved control systems are estimated to be around 200 EUR/kW in Aberthaw (UK).

Co-firing of biomass in coal-fired plants is a technical option; it is restricted by technical constraints and requires upgrades of power plant components. When compared to coal, biomass is characterized by lower carbon content, lower energy content, lower density, different ash, higher moisture content and a higher fraction of volatile matter (which causes it to have more “flaming combustion” and less “char combustion”). Additionally, biomass ash is more prone to forming deposits within the combustor, called “slagging” and “fouling” due to reactive salt compounds (K_2O). Altogether, these characteristics can affect the optimum sizing and design of the combustion chamber, as well as the ideal flow rate and location of combustion air (Ciolkosz 2010). Currently, hard coal-fired plants use the option of blending biomass to the combustibles with typical blending rates of 10-15% at Drax (UK), Maasvlakte (NL), Amer (NL), Gelderland (NL) and the IGCC plant Buggenum (NL). Capital costs for 45%

[11] Two different FB technologies are currently tested at large-scale: WTA (demonstrated at Niederaussem (DE)) and Dry Fining™ (demonstrated at Coal Creek in the US). A difference between the two drying processes is the WTA process first mills then dries the lignite while the DryFining™ process first dries then mills the lignite (EPA 2010). Both report net efficiency gains of up to 4%.

efficient hard coal plants with co-firing capability are 1390 EUR/kW (VGB PowerTech 2011a). Many multi-fuel plants are in the planning phase.

Specific CO_2 emissions of coal-fired plants primarily depend on generation process efficiency and the type of coal burned – the coal rank. The amount of heat released from coal combustion is determined by the coal rank, i.e. by carbon, hydrogen, and oxygen contents in the coal as well as - to a lesser extent - by the sulfur content. Hence, the ratio of carbon to heat content depends on these heat-producing components of coal, and these components vary by coal rank (EPA 2010). Carbon content increases with the duration of the carbonization process and it is lowest in peat/torf and lignite and highest in bituminous/anthracite coal. For a given coal rank there can be variations in the CO_2 emission factor depending on the coal bed from which the coal is mined. More details can be found in Table 13. The CO_2 emission reduction potential through co-firing of biomass is considerable.

Variable generation costs of coal-fired power plants are primarily determined by fuel costs and power plant efficiency. With steam coal prices of 99.2 USD/t in 2010, equivalent to 8.4 EUR/MWh (IEA 2011b), fuel costs of 15-25 EUR/MWh are realistic for hard coal plants. Cost for lignite corresponds to extraction cost since power plants are typically located next door to excavation sites. Lignite fuel costs of 1.4 EUR/MWh_{th} are assumed in EWI (2012); costs of up to 4 EUR/MWh_{th} are currently observed in some German mining areas. Operation and maintenance cost is relatively hard to determine and studies differ in the way these costs are allocated to variable or fixed costs. An exemplary calculation of O&M costs is performed by Wagner (2004, pp.29–30). A literature review shows that variable O&M costs around 6 EUR/MWh are typical for current coal-fired power plants. Adding CO_2 cost and O&M cost to fuel cost, we typically observe variable costs of 40-50 EUR/MWh for hard coal-fired plants and little less for lignite-fired power plants.

Capital cost CAPEX in EUR/kW	**IGCC**	**Ultra-super-critical**	**Super-critical**	**Sub-critical**	**Super-critical Retrofit**	**Lignite New (BoA)**	**Lignite Old**
(IEA et al. 2010) p.48	1870-3593 (USA)	1880	~ 1400	-	-	1650-2680	-
(IEA 2011b) table 10.4	1800	1575	1425	1200	-	-	-
(VGB PowerTech 2011a)	-	2100 **	1300	-	-	1400	-
(Capros 2011)	-	-	2066	1280	-	-	-
(EWI et al. 2010)	-	2250 *	1300 *	-	-	1950 *	1850 *
(Siemens 2008)	-	1700-2000	-	-	-	-	-
(RWE 2009)	-	-	1125-1410	-	1785	-	-
(RWI 1997) p.14	-	1862-2346				2336	1961
(EOn 2005)	-	-	-	-	800	-	-
(ECF 2010) Appendix A, p.3	1400-1600						
(Matthes & Ziesing 2011) p.31	1326-1722					1887	
(MIT 2007) p. 19, p. 30, based on 2000/2004 cost	1418	1020	998	960	-	998	-

Efficiency in %	IGCC	Ultra-super-critical	Super-critical	Sub-critical	Super-critical Retrofit	Lignite New (BoA)	Lignite Old
(IEA et al. 2010) p.53	39	46	41-45	-	-	41-45	-
(IEA 2011b) table 10.4	50	49	44	39	-	-	-
(VGB PowerTech 2011a)	-	50	45	-	-	43	-
(Capros 2011)	-	-	40	37	-	-	-
(EWI et al. 2010)	-	50 + *	46 *	-	-	48 *	44 *
(Siemens 2008)	-	50 +	-	-	-	-	-
(RWE 2009)	-	-	46	-	+ 2	-	-
(EOn 2005)	-	-	-	-	-	-	-
(Traber & Kemfert 2011)	-	-	43	34	-	43	38
(Kunz 2012)	-	-	41.7	-	-	-	37
(MIT 2007) p. 19, p.30	38.4	43.3	38.5	34;33-37	-	34.8	-

Fixed O&M Cost OPEX in EUR/kWa	IGCC	Ultra-super-critical	Super-critical	Sub-critical	Super-critical Retrofit	Lignite New (BoA)	Lignite Old
(IEA 2011b)	63	47	43	30	-	-	-
(VGB PowerTech 2011a)	-	42	26	-	-	28	-
(EWI et al. 2010) p.44	-	24	24	-	-	37	37
(Wagner 2004) pp.112-117 staff and maintenance fixed and variable cost	-	12.6+2.8 = 15.4	11.9+2.8 = 14.7	13.7+6.2 = 19.9	-	19.8+6.8 = 26.6	24.3 +6.8 = 31.1

Variable O&M Cost OPEX in EUR/MWh	IGCC	Ultra-super-critical	Super-critical	Sub-critical	Super-critical Retrofit	Lignite New (BoA)	Lignite Old
(IEA et al. 2010) table 3.7b	6-9	3	~ 6	6 - 9.5	-	6.5-10.5	6.5-10.5
(Traber & Kemfert 2011)	-	-	2.0	2.0	-	2.6	2.6
(MIT 2007) p. 19	-	5.63	5.63	5.63	-	7.5	-

CO_2 emissions in t/MWh***	IGCC	Ultra-super-critical	Super-critical	Sub-critical	Super-critical Retrofit	Lignite New (BoA)	Lignite Old
(EPA 2010)	0.93	0.93	0.94-0.98	0.97-1.01	-	-	-
(Siemens 2008)	-	0.669	0.761	1-1.2	-	-	-
VGB in (BINE 2011)	-	0.669	0.743	0.881	-	-	-
(Matthes & Ziesing 2008)	-	-	0.75	-	-	0.95	-
(MIT 2007) p. 19, p.30	0.832	0.738	0.83	0.931	-	0.103	-
(Strauss 2009) p. 324, 13.1, p. 331	-	0.68	0.69	0.72-0.78	-	0.8-0.88	1

* in 2020, ** in 2030 *** Direct emissions from burning, no life-cycle emissions.

Table 13: Technical and cost estimates for coal-fired power plants (without CCTS).
Source: Own compilation

3.3 Natural Gas

Open-cycle gas-fired power plants can be categorized into two sub-groups: Steam turbines and combustion turbines. Steam turbines are less flexible but more efficient than combustion turbines. Capital costs for a combustion turbine lie at around 400 EUR/kW in most studies. Material characteristics limit the heat in the gas combustion turbine process to 1200 °C at entry and 600 °C at exit. Net efficiency of energy conversion – which is a function of temperature gradient between heat source and sink – lies at little higher than 30% (Strauss 2009, p.333). When both turbine types, steam and combustion, are combined in sequential cycles, we refer to the combined cycle technology (CCGT) which exhibits cumulated efficiencies of up to 61% (Siemens H-type turbine) (Siemens 2008).[12] Total capital costs for a gas-fired combined cycle plant range between 625 EUR/kW for conventional types and 1210 EUR/kW for advanced CCGT plants. Investment into new plants can be avoided by retrofitting existing plants, the costs of which are very case-specific.[13]

Capital cost CAPEX in EUR/kW	**Combined Cycle New**	**Combined Cycle Old**	**Combustion Turbine New**	**Combustion Turbine Old**	**Steam Turbine**
(IEA et al. 2010) p. 48	790-1210	-	390-400	-	-
(VGB PowerTech 2011a)	800	-	650	-	-
(Capros 2011) p. 34	800	625	402	-	920
(IEA 2011b)	675	-	375	-	-
(Black & Veatch 2012) table 2	925	-	489	-	-
(RWI 1997) p.14	972		730		
(Matthes & Ziesing 2011) p.31	969-777		408-541		-
(DII 2012) p.36 (for 2050)	750	-	380	-	-
(ECF 2010) Appendix A, p.3	700-800				

Efficiency in %	**Combined Cycle New**	**Combined Cycle Old**	**Combustion Turbine New**	**Combustion Turbine Old**	**Steam Turbine**
(IEA et al. 2010) p.48	57-60	-	38	-	-
(VGB PowerTech 2011a)	60	-	45	-	-
(Capros 2011) p. 34	53.9	52.7	38.6	-	41.7
(IEA 2011b)	59	-	38	-	-
(Traber & Kemfert 2011)	58	-	35	-	40
(Kunz 2012)	-	54.2	-	34	39
(Siemens 2008)	60 +	-	46	-	-

[12] This technology is now commercially available and has been installed at the Irsching natural gas power plant.

[13] Gas power plant retrofits have been undertaken for instance at Didcot B (1360 MW CCGT, UK), Luenen Kellermann (163 MW CCGT, DE), Servola (180 MW CCGT, IT), Sannazzaro (250 MW CCGT, IT).

Fixed O&M cost OPEX in EUR/kW a	**Combined Cycle New**	**Combined Cycle Old**	**Combustion Turbine New**	**Combustion Turbine Old**	**Steam Turbine**
(VGB PowerTech 2011a)	20	-	19.5	-	-
(Capros 2011) p.34 *	20.0	15.6	11.9	-	16.6
(IEA 2011b)	17	-	15	-	-
(Wagner 2004) pp.112-117	-	-	9.19-12.29	11.07-14.77	-

Variable O&M cost OPEX in EUR/MWh	**Combined Cycle New**	**Combined Cycle Old**	**Combustion Turbine New**	**Combustion Turbine Old**	**Steam Turbine**
(IEA et al. 2010) table 3.7c, 5%	~ 5	~ 2.8-5	~ 4	-	-
(Capros 2011) p.34 *	2.0	2.1	2.1	-	2.1
(Traber & Kemfert 2011)	1.3	-	1.5	-	1.5
(Wagner 2004) pp.112-117	-	-	1.2	1.2	-

CO_2 emissions in t/MWh**	**Combined Cycle New**	**Combined Cycle Old**	**Combustion Turbine New**	**Combustion Turbine Old**	**Steam Turbine**
(Fritsche & Rausch 2008) p. vi, for CHP power	-	0.3241	-	0.4247	-
(Miller & Van Atten 2004) for United States, Table 3.12	-	~ 0.52-0.57	-	-	-
(Strauss 2009) p. 324, 13.1	0.33	0.36	0.55	0.55	-

* for 2005.

** Direct emissions from burning, no life-cycle emissions.

Table 14: Technical and cost estimates for gas-fired power plants.

Source: Own compilation

3.4 Oil

Although of marginal importance to electricity generation in terms of generated TWh, oil-fired plants do make up 51 GW capacity in the EU 27, amounting to a share of around 6 % in total installed capacity. 39 GW of installed oil-fired plant capacities use steam turbines and 12 GW are combustion turbines (Platts 2011). As peaking and occasionally price-setting units, oil-fired plants should be taken into account for sophisticated electricity market models. Oil-fired plants are primarily used as flexible-response units in exceptional peak load situations. Oil power plants work with open cycle combustion turbines, steam turbines or with a combined cycle.

Several existing oil-fired plants use gasification technologies similar to IGCC. Among these are Pernis (110 MW Oil, NL), Sannazarro (250 MW Oil, IT), Falconara (250 MW Oil, IT), Sarlux (550 MW Oil, FR) and ISAB Priolo Gargallo (500 MW Oil, IT). Other gasification plants exist in refineries. There are no advanced plans to install new oil-fired gasification plants due to high expected oil prices as of 2012. Hence, capital costs are not reported here.

Capital cost CAPEX in EUR/kW	**Combined Cycle**	**Combustion Turbine**	**Steam Turbine**
(EWI et al. 2010)	950*	400*	-
(Wagner 2004) pp.112-117	-	490-650	-

Efficiency in %	**Combined Cycle**	**Combustion Turbine**	**Steam Turbine**
(EWI et al. 2010)	60*	40*	-
(Traber & Kemfert 2011)	-	33	38
(Kunz 2012)	50	34	39

*Derived from figures for gas-fired turbines for 2020.

Fixed O&M cost OPEX in EUR/kWa	**Combined Cycle**	**Combustion Turbine**	**Steam Turbine**
(Wagner 2004) pp.112-117	-	5.91-6.96	-

Variable O&M cost OPEX in EUR/MWh	**Combined Cycle**	**Combustion Turbine**	**Steam Turbine**
(IEA et al. 2010) table 3.7g	-	15-18	-
(Traber & Kemfert 2011)	-	1.5	1.5
(Wagner 2004) pp.112-117	-	1.2	-

CO_2 emissions in t/MWh**	Combined Cycle	Combustion Turbine	Steam Turbine
(Miller & Van Atten 2004)		~0.53	
(CARMA 2012)	-	~0.4285 Wilmersdorf	~0.5098 Lichterfelde
(Matthes & Ziesing 2008)	0.35	-	-
(Strauss 2009) p. 324, 13.1	0.33	0.36-0.55	0.36-0.55

* Indications taken from gas turbines.

** Direct emissions from burning, no life-cycle emissions.

Table 15: Technical and cost estimates for oil-fired power plants (without CCTS).
Source: Own compilation

3.5 Carbon Capture, Transport and Storage (CCTS)

There is wide uncertainty about whether a technology called Carbon Capture, Transport, and Storage (CCTS) will at some point in the future be commercially available, and whether it will be used at scale as CO_2-abatement technology. While high hopes were initially placed in the CCTS-technology (IPCC 2005; IEA 2009), the last decade was full of disappointments with no successful demonstration project realized as of today (Hirschhausen et al. 2012). Different explanations have been provided to explain the "lost decade", and certainly overoptimistic cost reductions as well as underestimations of transport and storage costs have contributed to the failure. It is therefore important to run different cost scenarios to obtain a range of plausible outcomes. In this section, we provide an in-depth discussion of the costs of CCTS. As a matter of fact, it is impossible to obtain a coherent set of cost data, since not a single full-scale operation of capture, transport, and permanent storage exists. We nonetheless provide and compare existing estimates for the sake of transparency.

3.5.1 Capture costs

Today, there are three fundamentally different concepts on how to capture the carbon dioxide: (1) It can be captured before burning the fuel (pre-combustion), for which a complex chemical process and alternative burning equipment is required (IGCC-process); (2) capture of the CO_2 can also be done after combustion (post-combustion) in a conventional process of cleaning the flue gas which has been practiced for a long time; (3) burning the fuel in an pure oxygen environment, leads to cleaner flue gases but also much higher expenses and inflexibility (oxyfuel-process).

Pre-combustion refers to the removal of unwanted substances from the fuel prior to combustion. A coal gasification process is used to develop a synthetic gas consisting of carbon dioxide (CO_2), carbon monoxide (CO) and hydrogen (H_2). CO_2 is then separated and the remaining components are used for energy generation in an integrated gasification combined cycle (IGCC). Two disadvantages of this approach are its complexity and the fact that it may not be applied in retrofitting. Currently, pre-combustion can only be applied in IGCC plants of which only few exist to date.[14]

The post-combustion technology refers to the chemical treatment of flue gases with the aim of filtering harmful aerosols before emission into the air. For this purpose amine-based solvents such as monoethanolamine are used (Herzog et al. 2009). Post-combustion is already used on an industry level for chemical processes. However, it has not yet reached the implementation stage for energy generation. There is a possibility to implement post-combustion into already existing plants. Its main disadvantages are the significant decrease in efficiency and high operating costs.

[14] Several research projects are working on further developing the technology including CO_2CRC/HRL Mulgrave Capture Project (Australia) which is quantifying resource and performance parameters and COORIVA, a state-funded project in Germany which aims at providing a plant construction concept by 2015. The beginning of operation of the first IGCC plant with carbon capture in Kemper County, Mississippi is scheduled for 2014 (Global CCS 2012b).

Oxyfuel-combustion is a post-combustion technology that removes nitrogen from the air in order to burn the fuel with highly concentrated oxygen. Purified CO_2 results from the combustion process which is then separated in the cooling process. The most important cost driver in this approach is the large amount of energy needed in the generation of pure oxygen. Oxyfuel-combustion builds on existing technology and changes are only needed in the exhaust gas parts of power plants while leaving the steam cycle untouched. Additionally, no cleaning agent as in pre- and post-combustion capture is needed. Research on oxyfuel-combustion capture is at a very early stage with few demonstration plants (Schwarze Pumpe, Germany, 30 MW (Kluger et al. 2011)); other demonstration plants exist in France, Spain and Australia (Global CCS 2012a).

The difficulty of assessing capture costs is that no large-scale installation exists, and that all cost data produced thus far are highly case-specific. Consequently, *all* estimates should be treated very cautiously, and scenario analysis is particularly important in this context. Rubin et al. (2007) review a range of studies and report capital cost increases of up to 100 percent with high variations in the cost studies. Rubin & Rao (2002) point out several sources of these variations and uncertainties. These include different definitions of technologies and time frames as well as different measures of costs and varying assumptions about capital requirements in existing cost studies.

Table 16 shows the composition of investment costs. Costs for a gas-fired CCTS plant are about double the amount of a conventional CCGT power plant. The additional cost for a coal-fired CCTS power plant amounts to around 70% of the conventional plant cost. We conclude that costs for additional components of a coal-fired pre- and post-combustion CCTS plant range at around 1400 EUR/kW and 600 EUR/kW for a CCGT power plant. For oxyfuel CCTS plants, a lower cost increase of around 1000 EUR/kW is plausible since post-treatment at the exhaust section is dispensable.

Component cost in EUR/kW	**Gas CCGT CCTS**	**Coal Post-comb. CCTS**
Site preparation and licensing	36	72
Exhaust section	288	540
Circulation/ Stripper	60	120
Compression	144	216
Balance of capture plant	48	90
Host plant compensation	37	307
Base power plant	618	1920
Total	**1231**	**3265**

Table 16: Component costs of CCTS power plants.
Source: MacDonald (2011)

Rubin et al. (2007) provide cost estimations for CCTS implementation of some plant types (PC, IGCC and CCGT). Finkenrath (2011), ZEP (2011) and WorleyParsons & Schlumberger (2012) have recently extended these estimates to other technology and plant types. Updated results are shown in Table 17. While Rubin et al. (2007) refer to capital costs using the Integrated Environmental Control Model (IECM) to calculate projections, ZEP (2011) considers engineering procurement, construction cost and owner's costs (planning, designing, commissioning and contingency). Overnight capital costs given by Finkenrath (2011) are based on a review of recent cost studies which are calibrated with respect to their scope and revaluated applying the methodology from the IEA study on projected costs of energy generation (IEA et al. 2010). MIT (2007) reviews cost studies published 2000-2004 and bases its estimates on 2005 costs for comparative purposes. Both ZEP (2011) and Finkenrath (2011) exclude storage and transportation costs of CO_2, focusing exclusively on capture. WorleyParsons & Schlumberger (2012) present overnight construction costs for carbon capture plants taking into account equipment, material and labor costs as well as engineering management and contracting fees and related process and project contingencies. Like Finkenrath (2011), the study also takes into account different market situations for different world regions and gives conversion factors to adapt the costs adequately. Moreover the study presents a relationship between costs and upper heating value of the respective fuel to allow for conversion between different regions and fuel qualities e.g. in the case of lignite.

ZEP (2011) and WorleyParsons & Schlumberger (2012) also provide estimates on O&M costs which are displayed in Table 17. They include personnel and administration as well as cost for consumables and disposal of waste. Values are converted into euro per megawatt hour to allow for comparison. Apart from some progressive scenarios including an advanced single-shaft CCGT technology, O&M costs for post- and pre-combustion capture do not vary much across plant and fuel types in the ZEP report (2011). O&M costs for Oxyfuel combustion appear potentially lower. MIT (2007) summarizes O&M costs from earlier studies published 2000-2004. WorleyParsons & Schlumberger (2012) calculate variable and fixed O&M costs including equipment, materials and labor. For better comparability fixed O&M costs have been levelized using respective capacity and utilization values given in the respective study.

Due to auxiliary energy needed in the carbon capture process, the implementation of carbon capture will lead to a significant decrease of net efficiency (η) of power plants. Usually this is observed as *ceteris paribus* decline of energy output through CCTS implementation, but it may at the same time require increasing fuel input, as it is the case with IGCC plants. The effect can be captured either in the form of the fractional reduction in plant output per unit of energy input (= $1 - \eta_{CCS} / \eta_{ref}$) or as additional plant energy input per unit of output (= $\eta_{ref} / \eta_{CCS} - 1$) (Rubin et al. 2007). Estimates for the resulting efficiencies for first-generation plants are given in ZEP (2011), IEA (2011b) and MIT (2007) as displayed in Table 17.

Technology	Fuel type	Plant type	Investment Cost in EUR/kW_{el}				
			(Rubin et al. 2007)	(Finkenrath 2011)	(ZEP 2011)	(MIT 2007)	(WP & Schlumbg. 2012)
Post-Combustion	Hard Coal	Ultra-supercritical PC	-	3161*	2600**	3350	2894
		Supercritical PC	2478	2833*		3435	2949
		Subcritical PC	-	2386*		3579	-
	Lignite	Ultra-supercritical PC	-	3509	3109**	-	-
		Supercritical PC	-	3463		-	-
		Circulated fluidized bed /Subcritical PC	-	2565		-	-
	Natural Gas	F-class	1157	1292	1662**	-	1232
Pre-	Hard Coal	IGCC	2313	2679	3000**	-	2906

Combustion	Lignite	IGCC	-	3881	2911**	-	-
Oxy-Combustion	Hard Coal	Ultra-supercritical PC	-	2576	3691**	-	2697
		Supercritical PC	3053	2637		-	2778
	Lignite	Ultra-supercritical PC	-	3135	1983***	-	-
		Circulated fluidized	-	3681		3643	-

* These values have been adapted since there must have been a mistake in Finkenrath (2011).

** Upper bound from presented cost range.

Technology	Fuel type	Plant Type	Fixed & var. O&M cost in EUR/MWh		
			(ZEP 2011)	(MIT 2007)	(WP & Schlumbg. 2012)
Post-Combustion	Hard Coal	Average Power Plant	13.7	-	-
		Optimised power plant	13.1	-	-
		Base power plant	14.5	-	-
		Ultra-supercritical PC	-	12.8	14.7
		Supercritical PC	-	12.8	16.7
		Subcritical PC	-	12.8	-
	Lignite	Average Power Plant	15.9	-	-
	Natural Gas	Single-shaft F-class CCGT: Advanced Amine	12.6	-	5.2
		Advanced Single-shaft CCGT: Advanced Amine	9.8	-	-
Pre-Combustion (IGCC)	Hard Coal	Average Power Plant	13.8	-	12.7
		Optimised power plant	12.8	-	-
		Base power plant	15.0	-	-
	Lignite	-	13.9	-	-
Oxy-Combustion	Hard Coal	Optimised power plant	9.9	-	-
		Base power plant	11.2	-	12.0
	Lignite	-	9.1	-	-
		Circulated fluidized bed	-	14.8	-

Technology	Fuel type	Plant type	Efficiency in %			
			(Finkenrath 2011)	(ZEP 2011)	(MIT 2007)	(WP & Schlumbg. 2012)
Post-Combustion	Hard Coal	Ultra-supercritical pulverized	35.0	38.0	34.1	33.2
		Supercritical pulverized coal	31.0		29.3	27.1
		Subcritical pulverized coal	27.5		25.1	-
	Lignite	Ultra-supercritical pulverized	28.8	33.0	-	-
		Supercritical pulverized coal	28.2		-	-
		Subcritical pulverized coal	26.7		-	-
	Natural Gas	F-class	48.8	48.0	-	43.7
Pre-Combustion	Hard Coal	Integrated Gasification	33.2	38.0	-	32
	Lignite	Integrated Gasification	32.3	40.0	-	-
Oxy-Combustion	Hard Coal	Ultra-supercritical pulverized	35.0	35.4	-	33
		Supercritical pulverized coal	31.2		-	29.3
	Lignite	Ultra-supercritical pulverized	31.2	42.0	-	-
		Circulated fluidized bed	31.2		25.5	-

Table 17: Capital cost, efficiency and O&M cost for CCTS.

Source: Own compilation

3.5.2 Capture rate

The capture rate is also an important variable in a CCTS process. Because of the air separation unit the oxy-combustion process guarantees a high purity of the oxygen burned and therefore produces pure CO_2 which needs no post-treatment as with pre- and post-combustion technologies. It allows for capture rates of around 92% and higher. CO_2 capture rates of post- and pre-combustion are slightly lower at around 88% and 89%. Table 18 shows the capture rates of the technologies described above.

Technology	Fuel type	Plant type	Capture rate in %	
			(Finkenrath 2011)	(Viebahn et al. 2007)
Post-Combustion	Lignite		87	88
	Natural Gas	CCGT	87	88
Pre-Combustion	Hard Coal	IGCC	88	88
Oxy-Combustion	Hard Coal		92	99.5

Table 18: Capture rates.
Source: Own compilation

3.5.3 Transport costs

After capturing the CO_2 it needs to be transported to a storage site. Efficient transportation can be accomplished either via pipeline or ship transport. The capturing process should ideally deliver high-purity conditioned CO_2 ready for transportation. Onshore pipeline transport faces few technological barriers due to experience in the gas and oil sector and the CO_2 industry for enhanced oil recovery (CO_2-EOR) in the U.S. Offshore pipeline and ship transport are technologically feasible options but have not yet been demonstrated on commercial scale. Both on- and offshore pipelines require high capital costs for the infrastructure (CAPEX ~90%) and comparably low variable costs, mainly for fuelling compressor stations and monitoring. Ship transport is associated with relatively low upfront costs (CAPEX ~50%). Pipelines highly benefit from economies of scale resulting in strongly decreasing unit costs for higher pipeline capacities, while ships can be more efficient at small quantities and distances longer than 500 km. Moreover, ship capacity can be ramped up by adding ships while non-utilized pipeline capacity represents sunk costs. Additionally, ships have residual value in hydrocarbon transport which reduces the financial risk (ZEP 2011).

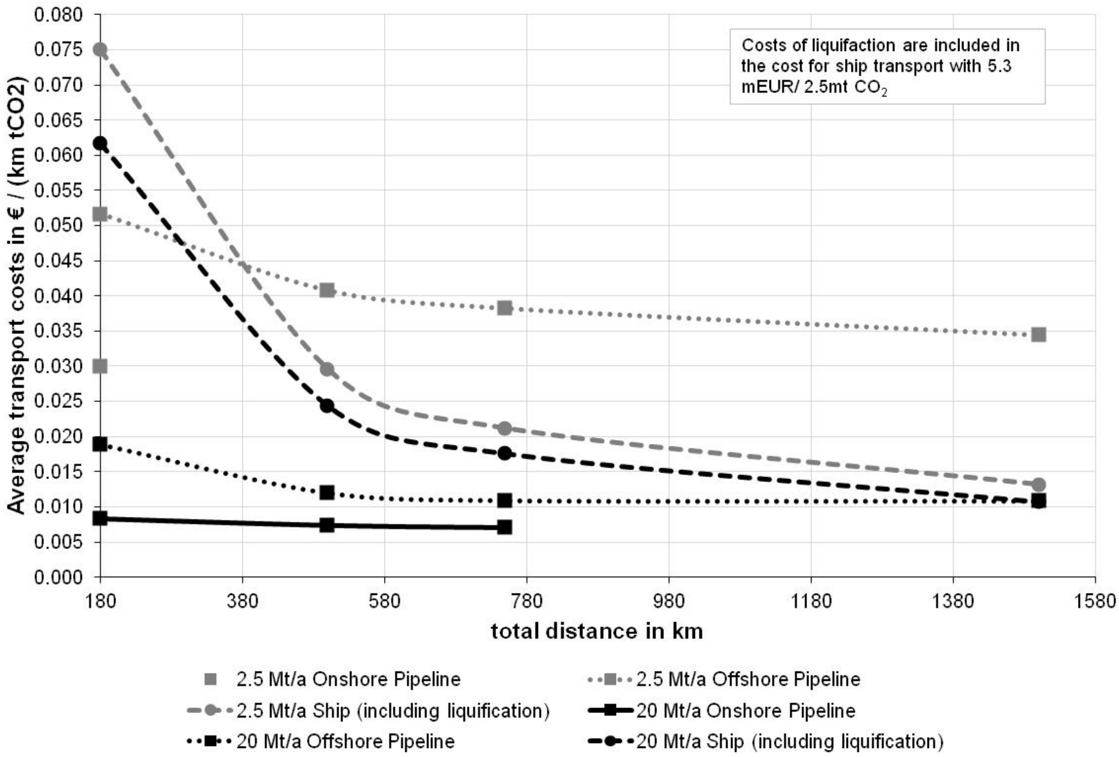

Figure 5: Average CO_2 transportation costs depending on total distance.
Source: Own calculations based on ZEP (2011)

Based on the comparison of several different studies on CO_2 pipeline transport costs, McCollum and Ogden (2006) have derived an approximate formula describing the relationship between capital costs of onshore CO_2 pipelines and respective CO_2 mass flow and total pipeline length:

$$\text{Pipeline Capital Cost } [€/\text{km}] = (9970 \cdot \text{m}^{0.35}) \cdot \text{L}^{0.13} \cdot \text{r}$$

Here, m = CO_2 mass flow rate [tonnes/day], L = pipeline length [km], and r = exchange rate for $ to €, as in McCollum and Ogden (2006). As shown in Figure 5 transportation costs are highly sensitive to volumes, transportation distances and the choice of carrier while capture technology and storage site characteristics play a minor role. For the purpose of this report emission volumes typical for the respective capturing technology and point to point connections are assumed. Since not all models can account for pipeline distances and power plant locations, we advise to use an average distance of 500 km (250 km onshore + 250 km offshore) between emission source and sink.

Technology type	Fuel type	Captured CO_2 in t/MWh (ZEP 2011)	Estimated Average Transport Costs in € /MWh for 180 km point-to-point transport (ZEP 2011)			
			Onshore Pipeline	***Offshore Pipeline***	***Ship***	**Cost Range**
Post-Combustion	Hard coal	0.827	4.47	9.23	11.16	4.47-11.16
	Lignite	1.091	5.89	12.18	14.73	5.89-14.73
	Natural gas	0.332	1.79	3.71	4.48	1.79-4.48
Pre-combustion	Hard coal	0.827	4.47	9.23	11.16	4.47-11.16
	Lignite	0.900	4.86	10.04	12.15	4.86-12.15
Oxy-combustion	Hard coal	0.887	4.79	9.90	11.97	4.79-11.97
	Lignite	0.857	4.63	9.56	11.57	4.63-11.57

Table 19: Transport costs of CO_2 for CCTS for different transport options.
Source: Own compilation

Technology type	Fuel type	Captured CO_2 in t/MWh (ZEP 2011)	Estimated Average Transport Costs in € /MWh for 500 km (250 km onshore + 250 km offshore) transport own calculation based on (ZEP 2011)			
			Transportation volumes			**Cost Range**
			High (>15 Mt/a)	**Medium (5-15 Mt/a)**	**Low (<5 Mt/a)**	
Post-Combustion	Hard coal	0.827	4.09	10.10	16.11	4.09-16.11
	Lignite	1.091	5.39	13.33	21.26	5.39-21.26
	Natural gas	0.332	1.64	4.06	6.47	1.64-6.47
Pre-combustion	Hard coal	0.827	4.09	10.10	16.11	4.09-16.11
	Lignite	0.900	4.45	10.99	17.53	4.45-17.53
Oxy-combustion	Hard coal	0.887	4.39	10.83	17.28	4.39-17.28
	Lignite	0.857	4.24	10.47	16.70	4.24-16.70

Table 20: Cost range for transportation costs of CO_2 for CCTS for transport volumes.
Source: Own compilation

3.5.4 Storage costs

In the last step of the CCTS process chain, the CO_2 is permanently stored in an underground reservoir. These reservoirs can either be depleted hydrocarbon fields or saline aquifers. In its 2011 study ZEP (2011) identifies the exploitable reservoir capacity, the well injectivity and lifetime, as well as potential liability obligations for the closure and post-closure period as the main cost drivers. Table 21 summarizes the estimated bounds for storage costs and compares them to figures reported by an earlier McKinsey study (2008).

Technology type	Fuel type	Captured CO_2 in t/MWh	Estimated Average Storage Costs in € /MWh	
		(ZEP 2011)	Own calculation based on ZEP (2011)	Own calculation based on McKinsey (2008)
Post-Combustion	Hard coal	0.827	2-12	7
	Lignite	1.091	2-16	9-10
	Natural gas	0.332	1-5	3
Pre-combustion	Hard coal	0.827	2-12	7
	Lignite	0.9	2-13	7-8
Oxy-combustion	Hard coal	0.887	2-13	7-8
	Lignite	0.857	2-12	7-8

Table 21: Storage Cost of CCTS.
Source: Own compilation.

3.5.5 Outlook

The availability of CCTS technology is primarily determined by technological progress. The progress made in improving the technologies again depends on the future development of fuel and CO_2 prices and policies concerning CO_2 mitigation and renewable energy sources. An analysis by MIT (2007) requires the CO_2 to reach 30 USD/tCO_2 in order for plants equipped with carbon capture technology to be competitive with coal-fueled power plants without CCTS. Calculations in Rammerstorfer & Eisl (2011) suggest that CCTS cannot be profitable at carbon prices below 70 EUR/t and favorable conditions regarding fuel prices and full load hours. As 2012 prices are lower than 10 EUR/t, CCTS cannot be considered competitive at the current state of technologies (Rammerstorfer & Eisl 2011). Estimates for the date of CCTS market deployment - at least as a retrofit technology - range from an optimistic 2020 (Markewitz et al. 2012) to 2070 (Biggs et al. 2000). Given the current state of the technologies, dates of ZEP (2011) seem realistic as they are also in line with other studies (Wagner & Foster 2011; IEA 2009).

Technology	Fuel type	(Biggs et al. 2000)	(ZEP 2011)	(Markewitz et al. 2012)
Post-Combustion	**Gas**	2025	2030	After 2020
	Coal	2070		
Oxy-combustion	**Gas**	2025	After 2030	
	Coal	2070		
Pre-combustion	**Gas**	2025	After 2030	
	Coal	2070		

Table 22: Availability of CCTS.
Source: Own compilation

As CCTS technology is currently in an early development stage, further improvements concerning both investment costs and efficiency of plants might be expected. Riahi et al. (2004) refer to the general quantitative model of cost reductions by Wright (1936) and project learning curves for CCTS implementation by estimating learning curves of other emission control technologies already in operation such as flue gas desulfurization (FGD) technology which is used in coal-fueled power plants to absorb SO_2. They show that the resulting learning rates are similar to those of other emission control technologies (e.g. selective catalytic reduction (SCR) systems controlling NO_x emissions) and thus assume that FGD technology learning rates may be used for estimating future development of CCTS costs. Therefore, investment costs for CCTS are predicted to decline by 13% for every doubling of capacity. This is in line with goals for investment cost reduction of 10-12% every 10 years until 2030 set in the Technology Road Map Carbon Capture and Storage (IEA 2009). A good review of historic cost evolutions in CCTS deployment can be found in Yeh and Rubin (2010, p.11).

3.5.6 Total costs

The total variable costs in EUR/MWh are determined by the employed capture technology, the emission factor of the fuel in use as well as by the infrastructure used for transport and storage. To give a simplified but informative estimate of the total variable costs we assume an average amount of 5 to 15 Mt is transported over a distance of 500 km (250 km onshore and 250 km offshore) and use the average of the collected estimates on storage costs. The estimated costs of the individual CCTS process steps are expressed as part of the variable O&M costs which are summarized in Table 34.

3.6 Combined Heat and Power (CHP)

CHP technology is relevant especially for power plants located in industrial centers or urban areas close to end-users. Almost any fuel is suitable for CHP but natural gas is by far the most attractive fuel for use in CHP according to the IEA (IEA 2010). The amount of electricity produced globally from CHP has been gradually increasing, and reached more than 10% of total global electricity production in 2011. The European Union generates 11% of its electricity using cogeneration (IEA 2011b). Denmark, Finland and the Netherlands have high penetration rates while Eastern European countries have abundant low-efficiency CHP capacity. Different CHP technologies exist (Capros 2011):

- Backpressure steam turbine – Here, power and heat production are directly coupled. In order to use backpressure turbines at times with peak power demand and low heat demand, one needs appropriate heat storage devices or auxiliary condensers (Konstantin 2007). Backpressure steam turbine power plants follow heat demand.

- Extraction-condensing steam turbine – A part of the steam is extracted from the turbine to be used for heat consumers. The remaining part is used for condensation in the turbine. Such plants can vary the share of heat and power production and they do not have to follow heat demand.

- Gas Turbine with heat recovery – This system uses flue gases from the gas combustion process.

- Combined Cycle with heat extraction – Steam is extracted from the steam cycle to be used for heat consumption.

- Internal combustion engines with cogeneration are often designed as packaged CHP units with low capacity.

- Other technologies include e.g. fuel cells.

Efficiency of CHP units is slightly lower than that of their non-CHP equivalents. But overall efficiency combined with heat production is higher. Overall efficiencies of 90% are attainable with modern technology. Capital costs of CHP units deviate from conventional plants since an additional heat grid connection must be installed. However, these costs are very case-specific, and it is difficult to give a general approximation of these.

In CHP plants, operation is often dictated by the demand for heat from the system rather than by the demand for power (thermal load following) (IEA 2011b). In the absence of some form of thermal storage to enable constant generation, CHP generation can be considered as must-run feed-in power in electricity specific models.

Table 23 shows that CHP plants typically have full load hours in the range of 4000-5000 h/a (45-57%). The relative competitiveness of CHP depends primarily on the value of the heat generated. Table 23 presents details on heat credits. A heat credit can be considered as negative cost and it is subtracted from total unit costs to establish an equivalent of the levelized costs of producing only electricity (IEA et al. 2010). This heat value varies widely according to country and the nature of the energy service provided. Given that CHP produces heat as well as power, one cannot allocate total generating costs to electricity production alone. Parcelling out cost shares, however, is highly impractical since heat and power are genuine joint products (IEA et al. 2010). The convention adopted is thus to allocate to power generation the total costs of generation minus the value of the heat produced. Konstantin (2007, chap.8) provides more details on the division of cost between heat and electricity production and different allocation algorithms.

	Full load hours (use rate) for electricity production	**2010**	**2020**	**2030**	**2040**	**2050**
General	(DLR & SRU 2010) table 9.13	4000 (45%)	4000 (45%)	4000 (45%)	4000 (45%)	4000 (45%)
General	(IEA et al. 2010)	5520 (63%)	-	-	-	-
Coal	(Wagner 2004) Table 11-6	6550_{el} 3000_{th}	6550_{el} 3000_{th}	-	-	-
Gas CC	(Wagner 2004) Table 11-7	2500_{el} 2500_{th}	2500_{el} 2500_{th}	-	-	-
Industrial	(Konstantin 2007) p. 316	6000_{el} 5500-7000_{th}	-	-	-	-

	Heat credit €/MWh_{therm}	**2010**	**2020**	**2030**	**2040**	**2050**
General	(DLR & SRU 2010) table 9.13	37	39	42	45	50
General	(IEA et al. 2010)	33	-	-	-	-
Coal	(IEA et al. 2010) table 3.7e	42-51	-	-	-	-
Gas	(IEA et al. 2010) table 3.7e	9-32	-	-	-	-
Biogas	(IEA et al. 2010) table 3.7e	13.5	-	-	-	-

Table 23: Parameters for CHP plants.
Source: Own compilation

3.7 Dynamics of conventional plants in different studies

Different studies treat the dynamics of capital costs for conventional power plants in various ways. Figure 6 shows capital cost developments assumed in the prominent study of the European Energy Roadmap 2050. For relatively mature technologies such as gas and steam turbines without CCTS, the PRIMES projections are conservative with little cost cuts in future. In general, all technologies in the PRIMES model become cheaper over time, owing to technological progress and input cost reductions. Table 32 provides more details with a comparison to other studies.

The energy market equilibrium model PRIMES (EC 2011; Capros 2011) anticipates the cost evolution and thereby takes into account scale effects of mass production and technological progress through research and development. However, it does not endogenously determine learning-by-doing effects (due to non-convexities) but in a scenario variation. For example, PRIMES projects a relatively sharp decline in CCTS capital costs starting from a high level with 3481 EUR/kW for Oxyfuel coal plants in 2010 and then decreasing to 2315 EUR/kW in 2030. A little less optimistic cost reduction by 20-25% is projected in IEA et al. (2010) for capture in coal-fired plants between 2015 and 2030. We believe PRIMES projections to be too optimistic in the context of CCTS.

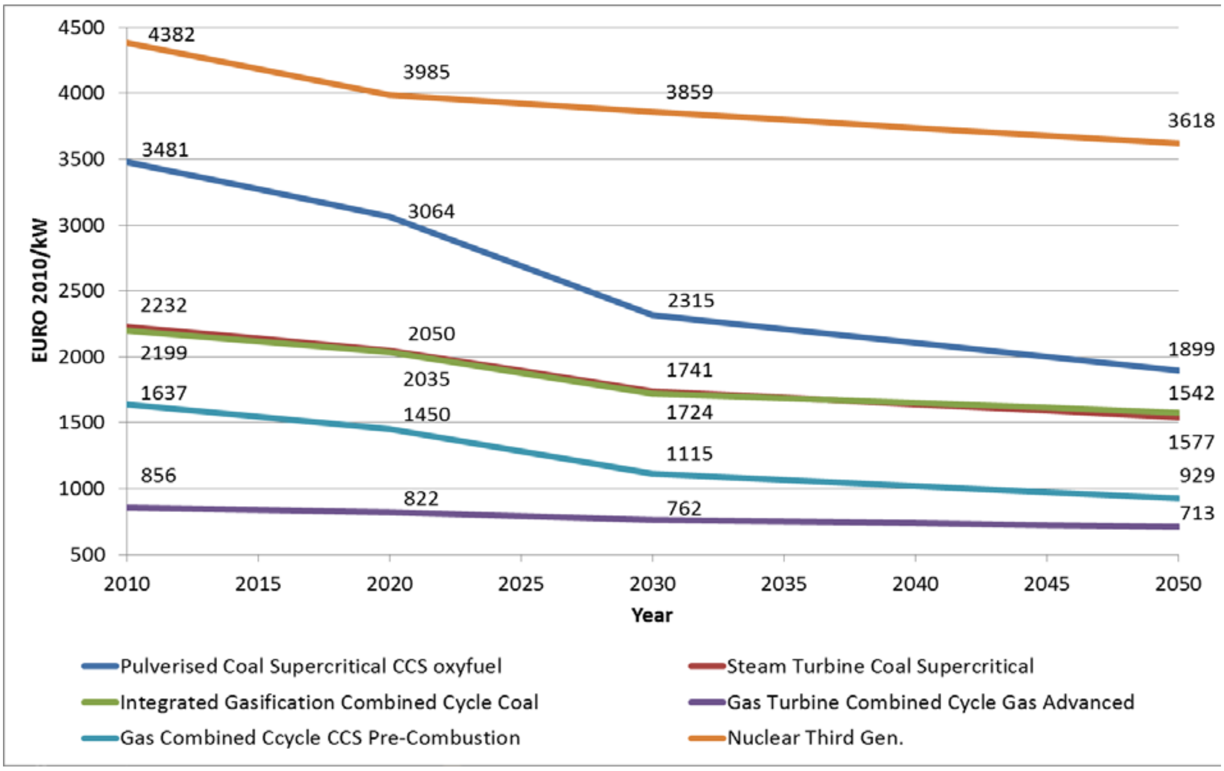

Figure 6: Capital cost evolution in the PRIMES model.

Source: EC (2011) p.67

According to the PRIMES model assumptions, 2050 capital costs for solar PV and solar thermal plummet to around one third of 2010 values. We believe this to be a very pessimistic development, not the least since a drastic cost degression for solar power has materialized in the latest years, rendering many recent cost projections obsolete. Further cost reductions for solar PV systems can be expected from mass production effects and system simplification of the classical parts such as instrumentation & control system, electric equipment, civil engineering and site specific improvements (VGB PowerTech 2011a). Solar thermal is likely to see improvements in the cost of the storage and the reflector/absorber part while little cost cuts are expected on the steam turbine part (VGB PowerTech 2011a). Wind energy and geothermal power plants experience only moderate improvements until 2050 according to the PRIMES model.

Technology	Source	2010	2015	2020	2025	2030	2035	2040	2045	2050
Nuclear Gen 3	(EC 2011) p.67	4382	-	3985	-	3859	-	-	-	3618
Coal Supercritical w/o CCTS	(EWI et al. 2010)	1300	-	1300	-	1300	-	1300	-	1300
	(VGB PowerTech 2011a)	1400	-	1400	-	1400	-	-	-	-
	(EC 2011) p.67	2199	-	2035	-	1724	-	-	-	1577
	(IEA 2011b)	1425	-	1425	-	1425	-	-	-	-
Coal Ultra-Supercritical w/o CCTS	(VGB PowerTech 2011a)	-	-	2100	-	1800	-	-	-	-
	(IEA 2011b)	1575	-	1575	-	1575	-	-	-	-
Coal IGCC w/o CCTS	(EWI et al. 2010)	-	-	2250	-	1875	-	1763	-	1650
	(EC 2011) p.67	2232	-	2050	-	1741	-	-	-	1542
	(IEA 2011b)	1800	-	1800	-	1650	-	-	-	-
Gas Combined Cycle w/o CCTS	(EWI et al. 2010)	950	-	950	-	950	-	950	-	950
	(VGB PowerTech 2011a)	800	-	800	-	800	-	-	-	-
	(EC 2011) p.67	856	-	822	-	762	-	-	-	713
	(IEA 2011b)	675	-	675	-	675	-	-	-	-
Gas CT w/o CCTS	(IEA 2011b)	375	-	375	-	375	-	-	-	-
Coal Post-Combustion CCTS	(IEA 2011b)	2565	-	2565	-	2025	-	-	-	-
	(MacDonald 2011) App. B SuperCritical	3265	2588	2381	2268	2162	2063	1969	-	-
	(MacDonald 2011) App. B SuperCritical Retrofit	3324	2550	2250	2099	1961	1832	1714	-	-
Coal IGCC Precombustion CCTS	(IEA 2011b)	2610	-	2610	-	2175	-	-	-	-
	(MacDonald 2011) App. B	3364	2986	2821	2611	2419	2242	2080	-	-
Coal Oxyfuel CCTS	(IEA 2011b)	2760	-	2760	-	2025	-	-	-	-
	(EC 2011) p.67	3481	-	3064	-	2315	-	-	-	1899
	(MacDonald 2011) App. B Supercritical	3313	2652	2428	2294	2172	2059	1954	-	-
	(MacDonald 2011) App. B Supercritical Retrofit	3271	2539	2242	2065	1908	1766	1638	-	-
CCGT Precomb. CCTS F-Class	(IEA 2011b)	1215	-	1215	-	1013	-	-	-	-
	(EC 2011) p.67	1637	-	1450	-	1115	-	-	-	929
	(MacDonald 2011) App. B	1057	968	940	895	854	816	780	-	-
CCGT Post Comb. CCTS	(MacDonald 2011) App. B	1231	1091	1040	1000	960	924	889	-	-

Table 24: Evolution of capital cost for fossil-fired power plants in different studies.
Source: Own compilation

4 Flexibility and other Technical Parameters

4.1 Power plant flexibility

An increasing number of power market models include technical parameters to account for the operational flexibilities of thermal power plants. Flexibility in this context refers to the short term power plant perspective and describes the ability of generation technologies to deliver electrical energy. The flexibility includes the capability to adjust the operating status (unit commitment) as well as the generation (dispatch) of the power plant. In power market models the following parameters are often used to characterize the operational flexibility of power plants:

- Start-up time,
- Ramping load gradients,
- Minimum load,
- Minimum up- and downtime.

In addition to the technical parameters, economic parameters in particular costs and efficiencies are depicted. In particular, start-up processes impose additional costs as the fuel consumption and manpower requirements are higher than in hours the plant operates at rated capacity. Furthermore, operating a plant below rated capacity influences the efficiency of the entire generation process. This effect is captured in the part load efficiency, which itself is a determinant of generation costs. In the following section, the operational and economic parameters are listed for different generation technologies. It is important to note that these parameters are generally specific for individual power plants but some general findings can be made.

4.1.1 Start-up time and costs

Start-up time represents the fact that power plants need time to start-up in particular to synchronize the generator to the grid frequency and thus to deliver load in the following time periods. Main restrictions for start-up times are thermal stress through extreme temperature and pressure differences within thick-walled components of a plant. This holds ture particularly for classical base load power plants with attached steam cycles. Hydroelectric power plants and open cycle gas turbine power plants have less complicated start-up and ramping procedures. They can provide power with high load gradients and at modest start-up costs with minimum lengths.

An additional fact is that the start-up time is (among others) a function of the status, in particular of the warmth of a power plant. In the literature cold, warm and hot starts are distinguished:[15,16]

[15] Black starts (start-ups in times of blackout) are not further analyzed here.

[16] The definition of start-up types and their associated downtimes may differ due to e.g. unit size.

- Cold start – A power plant has been shut down for more than 50 hours e.g. for revision (Albert et al. 2009).
- Warm start – A power plant has been turned off for more than 8 hours and less than 50 hours.
- Hot start – A power plant has been switched off within 8 hours of the next start-up (Albert et al. 2009). Hot starts are characteristic for power plants running in a daily cycling mode which are shut down over night and take up generation in the morning.

In addition to technical limits on start-up time, there is need to consider start-up costs which are composed of three main factors according to Lefton and Besuner (2006a):

- Costs of start-up fuels, auxiliary electricity, chemicals and additional manpower required for unit start-up. There is higher use of fuel and manpower while synchronizing turbine and generator, and during the subsequent process of adjusting and controlling steam pressure and temperature.
- Depreciation of the components exposed to wearing along with higher maintenance, overhaul capital expenditures, unit life shortening, and increased forced outage rates.
- Lost profits due to lower part load efficiency of power plants when ramping.

In Table 25 a distinction between these start-up types is made and typical values for start-up times of conventional energy generation facilities, measured in hours from notification to finished synchronization of the generator. Indications of start-up cost are also included, differentiated by type of start-up and separated into fuel- and fatigue-related cost.

A breakdown of cycling-related costs shows that 52-57% of capital and maintenance cost is due to the boiler, 22-27% due to the turbine, 9-15% due to plant balancing, 2-3% due to control and 5-8% due to fuel handling (Lefton n.d., pp.6–7). A detailed study on start-up cost levels can be found in a study of NREL and WECC (Kumar et al. 2012), where lower-bound estimates for cycling cost are reported. A high level of detail is provided regarding different technology types. Furthermore, values for additional fuel costs of start-up as well as depreciation costs are found in the dena I grid study (2005), Grimm (2007) and an application in Traber & Kemfert (2011). For analyzing daily cycling processes, costs for a hot start are relevant. They amount to approximately one third of the additional costs for a cold start (Klemm 2007). The report of NREL and WECC assumes hot start costs between one and two thirds of cold start cost (Kumar et al. 2012). This is confirmed for coal, lignite and CCGT plants by indications in Ehlers (2011, p.94), who analyzes published bids from the PJM electricity market to approximate start-up costs. Except for nuclear power there exist differences between hot, warm, and cold start costs.

Start-up time

Hot start-up time

	Nuclear	Coal SuperC	Coal SubC	Lignite New	Lignite Old	Gas CC	Gas CT	Gas ST	Oil
(Meibom et al. 2008) p.122 table 33	-	4 h	-	-	-	2 h	0 h	-	-
(Grimm 2007) p. 54 table 4.2	-	1 h	-	-	-	50-85 min	-	-	-
(Wacek 2010)	-	5 h	-	-	-	30 min	10 min	-	-
(VDE 2012) p. 24	-	2 h	3 h	4 h	6 h	30-90 min	<6 min	-	-
(Black & Veatch 2012)	2 %/min (<20 min)	-	-	-	-	2.5 %/min (<40 min)	22.2 %/min (<5 min)	-	-

Warm start-up time

	Nuclear	Coal SuperC	Coal SubC	Lignite New	Lignite Old	Gas CC	Gas CT	Gas ST	Oil
(Meibom et al. 2008) p.122 tbl 33	-	8 h	-	-	-	4 h	0 h	-	-
(Hundt et al. 2009)	-	2 h	-	2 h	-	1 h	0 h	1 h	-
(Grimm 2007) p. 54 table 4.2	-	4 h	-	5 h	-	3 h	20 min	-	-

Cold start-up time

	Nuclear	Coal New/ SuperC	Coal Old/ SubC	Lignite New	Lignite Old	Gas CC	Gas CT	Gas ST	Oil
(Meibom et al. 2008) p.122 tbl 33	-	12 h	-	-	-	5 h	0 h	-	-
(Grimm 2007) p. 54 table 4.2	50 h	6 h	-	9 h	-	5 h	-	-	-
(Traber & Kemfert 2011) *	24 h	7.3h	7.3 h	12.8 h	12.8 h	2 h	1 h	2 h	1 h
(VDE 2012) p. 24	-	4 h	10 h	6 h	10 h	2-4 h	<6 min	-	-

* Not power-plant sharp

Start-up costs

Fuel-related start-up cost (hot start) in EUR/ΔMW or fuel consumption in MWh_{th}/MW_{el}

	Nuclear	Coal SuperC	Coal SubC	Lignite New	Lignite Old	Gas CC	Gas CT	Gas ST	Oil
(Meibom et al. 2008) Table 33	-	3.56 $MWh_{th}/\Delta MW_{el}$	-	-	-	1.5-1.8 $MWh_{th}/\Delta MW_{el}$	0.02 $MWh_{th}/\Delta MW_{el}$	-	-
(Kumar et al. 2012) p.15 modern	-	28.5 €/ ΔMW	29-43.5 €/ ΔMW	-	-	23 €/ ΔMW	16.5 €/ ΔMW	19.5 €/ ΔMW	-
(Kumar et al. 2012) p.13-14 median	-	40.5 €/ ΔMW	44-70.5 €/ ΔMW	-	-	26.2 €/ ΔMW	24 €/ ΔMW	27 €/ ΔMW	-
(Grimm 2007) 30% of cold cost	-	5.3 €/MW	8.4 €/MW	-	-	2.6 €/MW	-	-	-

Fuel-related start-up cost (warm start) in EUR/ΔMW or fuel consumption in MWh_{th}/MW_{el}

	Nuclear	Coal SuperC	Coal SubC	Lignite New	Lignite Old	Gas CC	Gas CT	Gas ST	Oil
(Meibom et al. 2008) Table 33	-	5.7 $MWh_{th}/\Delta MW_{el}$	-	-	-	1.5-1.8 $MWh_{th}/\Delta MW_{el}$	0.02 $MWh_{th}/\Delta MW_{el}$	-	-
(Kumar et al. 2012) p.13-14 median	-	48 €/ ΔMW cap	49-117 €/ ΔMW cap	-	-	41.3 €/ ΔMW cap	94.5 €/ ΔMW cap	43.5 €/ ΔMW cap	-
(Kumar et al. 2012) p.13-14 modern	-	42 €/ ΔMW cap	46-71 €/ ΔMW cap	-	-	33 €/ ΔMW cap	21 €/ ΔMW cap	34.5 €/ ΔMW cap	-
(Grimm 2007) 50% of cold cost	-	17.7 €/MW	-	-	-	28 €/MW	8.8 €/MW	-	-

Fuel-related start-up cost (cold start) in EUR/ΔMW or fuel consumption in MWh_{th}/MW_{el}

	Nuclear	Coal New/ SuperC	Coal Old/ SubC	Lignite New	Lignite Old	Gas CC	Gas CT	Gas ST	Oil CT
(Meibom et al. 2008) p.122 table 33	-	11.28 $MWh_{th}/\Delta MW_{el}$	-	-	-	4.5-5.4 $MWh_{th}/\Delta MW_{el}$	0.06 $MWh_{th}/\Delta MW_{el}$	-	-
(dena 2005) table 14-8	16.7 $MWh_{th}/\Delta MW_{el}$	6.2 $MWh_{th}/\Delta MW_{el}$	-	6.2 $MWh_{th}/\Delta MW_{el}$	-	3.5 $MWh_{th}/\Delta MW_{el}$	1.1 $MWh_{th}/\Delta MW_{el}$	-	-
(Kumar et al. 2012) p.13-14 median	-	78 €/ ΔMW cap	79-110 €/ ΔMW cap	-	-	59 €/ ΔMW cap	77 €/ ΔMW cap	56 €/ ΔMW cap	-
(Kumar et al. 2012) p.13-14 modern	-	74 €/ ΔMW cap	67-71 €/ ΔMW cap	-	-	45 €/ ΔMW cap	28.5 €/ ΔMW cap	43.5 €/ ΔMW cap	-
(Grimm 2007)	-	35.3 €/MW	-	-	-	56 €/MW	17.6 €/MW	-	-

	Nuclear	Coal New/ SuperC	Coal Old/ SubC	Lignite New	Lignite Old	Gas CC	Gas CT	Gas ST	Oil CT
(Traber & Kemfert 2011) *	35.07 €/ ∆MW	44.64 €/ ∆MW	44.64 €/ ∆MW	27.9 €/ ∆MW	27.9 €/ ∆MW	75.95 €/ ∆MW	23.87 €/ ∆MW	86.8 €/ ∆MW	18.92 €/ ∆MW
(Ehlers 2011) p.94 *	140 €/ ∆MW	-	30 €/ ∆MW	-	60 €/ ∆MW	20 €/ ∆MW	1 €/ ∆MW	-	0 €/ ∆MW

* Does not differentiate between different coal, lignite and gas power plant types.

Cold-start depreciation cost in EUR/∆MW

	Nuclear	Coal New SuperC	Coal Old SubC	Lignite New	Lignite Old	Gas CC	Gas CT	Gas ST	Oil
(Traber & Kemfert 2011)	1.7	5	1.5	3	1	10	10	10	5
(dena 2005) table 14-8	1.7	4.8	-	3	-	10	10	-	-

Table 25: Start-up parameters.
Source: Own compilation.

Table 25 summarizes cost and technical data collected from various sources. One full start-up can require additional fuel use with costs in the order of 30,000 EUR (hot) and 100,000 EUR (cold) for coal-fired plants of 1000 MW size. The cost for starting a nuclear power plant is even higher with 200,000 EUR per start as reported in Ehlers (2011, p.94). Note that some indications consider unit operations of power plants while others are used for models without powerplant-specific modeling.[17] All in all, the given numbers demonstrate the high flexibility of modern power plants contrary to the indications in some studies such as IEA (2011a). Specific start-up cost differences are rather modest across technologies.

4.1.2 Ramping gradients and ramping costs

Ramping load gradients describe the ability to adjust the production level within a certain timeframe (here: minute). As for start-up times, the main reason for ramping gradients is to reduce the thermal stress by avoiding rather extreme temperature and pressure differences within components of a plant. It is important to note that the ramping gradient of power plants depends on the investigated timeframe and the way a power plant is operated. In the shortest term, power plants based on steam cycles are able to provide additional energy very quickly by releasing thermal energy stored in the generation process. Afterwards, an increase of the fuel flow is required to maintain the additional energy output. However, the ability to provide quick output increases requires the power plant to be operated below optimal conditions to store the required thermal energy. On the other hand, generation

[17] In the second case, the whole fleet of power plants is regarded as a block. For models disregarding power plant unit commitment, start-up limits and costs do not have to be applied. As NREL and WECC (Kumar et al. 2012) put it: "Use of the cycling cost numbers without accounting for actual unit operations can result in significant under/over estimation of power plant cycling costs."

technologies characterized by less thermal storage capacity (e.g. Gas Combined Cycle) increase their output by directly increasing the fuel intake. Adding to the additional fuel cost, ramping costs reflect the additional capital and maintenance costs of changing energy output of a plant.

Table 26 depicts the ramping gradients as well as costs. Generally, the provided figures are in a comparable range with lower ramping gradients for power plants based on a steam cycle process compared to gas turbines. On the other hand, open cycle gas turbine power plants are characterized by less complicated ramping procedures and thus can provide power with high load gradients. However, IEA (2011a) does not provide power plant specific data on ramping gradients and thus the values are the lowest for all listed generation technologies. Ramping costs values are in general relatively low compared to start-up values. Still they can be relevant for generation technologies which are designed for baseload applications, for instance coal, than for peaking technologies (Kumar et al. 2012).

Ramping load gradient limit in %-P_n/min

	Nuclear	Coal New/ SuperC	Coal Old/ SubC	Lignite New	Lignite Old	Gas CC	Gas GT	Gas ST	Oil CT
(Hundt et al. 2009)	-	4	-	3	-	6	20	6	20
(Gwisdorf & Reissaus 2009)	3.3	4.1	3.6	-	-	5	6.7	-	6.7
(Grimm 2007) p. 54 table 4.2	5-10	4-8	-	2-3	-	4-10	10-25	-	-
(Lambertz 2011)	-	3.4	-	3	-	4.3	-	-	-
(Meibom et al. 2008) p.122 tbl 33	-	2.05	-	-	-	2.29-2.75	10	-	-
(VDE 2012) p. 24	-	6	1.5-4	4	1-2.5	2-8	8-15	-	-
(Klobasa et al. 2009)p.30	5-10	-	4-8	-	4-8	8-12	10-30	-	-
(Black & Veatch 2012)	5	-	2	-	-	5	8.33	-	-
(Steck & Mauch 2008)	5 (PWR) 1 (BWR)	-	3 up 5 down	-	2 up 5 down	-	15	7	4 up 5 down
(IEA 2011a)*	0.25	0.83	0.58	0.58	0.58	0.83	-	0.58	-
(ECF 2010) App. A, p.6	0.66	0.66				0.83			1

* Values indicated for the Nordic market and not power-plant sharp.

Ramping cost in EUR/ΔMW

	Nuclear	Coal SuperC	Coal SubC	Lignite New	Lignite Old	Gas CC	Gas GT	Gas ST	Oil
(Kumar et al. 2012) p.16	-	1.3 €/ ΔMW cap	1.5-1.7 €/ ΔMW cap	-	-	0.25 €/ ΔMW cap	0.66 €/ ΔMW cap	1.17 €/ ΔMW cap	-

Table 26: Ramping parameters.

Source: Own compilation

4.1.3 Minimum load, up- and downtime

In addition to the operating values given on start-up times and ramping gradients, minimum load levels and minimum up- and downtimes are helpful in modeling power plant unit commitment and dispatch. Minimum load levels refer to the lower generation limit at which a plant can be effectively operated. Below the minimum load level a stable operation may not be achievable due to e.g. insufficient temperatures or excessive emissions (Harris 2006, p.52). Therefore, thermal power plants can operate in the capacity range from minimum load to rated capacity. It is important to point out that the minimum load depends on the design of the generation process. For instance, for lignite power plants with an optimized plant design (e.g. BoAplus) a reduction of the minimal load to 35% or even 17.5% (using a two-boiler-concept) is expected.

Additionally, minimum up- and downtimes (or online/offline times) are used to characterize the limitations on flexibility of thermal power plants. These are commonly used in particular in power plant unit commitment models (Kumar et al. 2012). Up- and down-times are in principle no 'hard' physical limits but they can be considered as economic limits since operators are interested in keeping the number of start-ups and shut-downs low in order to avoid for instance excessive thermal stress on power plant equipment.

Minimal load as percentage of net generation capacity

	Nuclear	Coal New SuperC	Coal Old SubC	Lignite New	Lignite Old	Gas CC	Gas GT	Gas ST	Oil
(VDE 2012)	-	20	25-40	40	50-60	30 - 50	20 – 50	-	-
(Meibom et al. 2008) p.122 tbl33	-	50	-	-	-	50	10	-	-
(Grimm 2007) p. 47	-	-	35	-	-	35	20-100	-	-
(Lambertz 2011)	-	25	-	50 (BoAplus: 17.5 - 35)	-	30 - 40	-	-	10
(dena 2005) p. 280	40	-	38	-	40	33	20	-	-
(Klobasa et al. 2009) p.30	40	-	40	-	40	40	0	-	-
(Steck & Mauch 2008)	35 (PWR) 60 (BWR)	-	30	-	50	40	50	-	40
(Black & Veatch 2012)	50	-	40	-	-	50	50	-	-
(ECF 2010) App. A, p.6	50	50				40			50

Minimum uptime/downtime

	Nuclear	Coal New SuperC	Coal Old SubC	Lignite New	Lignite Old	Gas CC	Gas GT	Gas ST	Oil
(Meibom et al. 2008) p.122 tbl 33	-	6 h / 4 h	-	-	-	4 h / 1 h	0 h / 0 h	-	-
(Hundt et al. 2009)	-	-	4 h / 2 h	-	6 h / 6 h	4 h / 2 h	1 h / 0 h	4 h / 2 h	-
(Ehlers 2011)	168 h / -	-	16 h / -	-	24 h / -	8 h /-	0 h / -	-	-
(Schuewer et al. 2010) p.16	24-48 h / 24-48 h	-	6-15 h / 6-15 h	-	-	1-6 h / 1-6 h	1-6 h / 1-6 h	1-6 h / 1-6 h	1-6 h / 1-6 h
(Klobasa et al. 2009) p.30	-	-	3 h / -	-	3 h / -	3 h / -	0 h / -	-	-
(Steck & Mauch 2008)	24 h / 24 h	-	3 h / 3 h	-	5 h / 8 h	1 h /1 h	0.25 h / 0.25 h	-	2 h / 2 h
(ECF 2010) App. A, p.6	6 h / 4 h	4 h / 4 h				6 h / 4 h			6 h / 4 h

Table 27: Minimum load, up- and downtime parameters.
Source: Own compilation

4.1.4 Part load efficiency

Operating a plant below the rated capacity typically reduces the efficiency of the entire process which is expressed by the part load efficiency. The decrease of efficiency increases the fuel usage and thus generation costs. As any power plant, independent of the exact technology, requires a certain amount of energy to keep the system running and thus synchronized, it is obvious that the share of this energy amount decreases with higher loads. Henceforth, the efficiency defined as the relation from fuel input to delivered load increases with the loading of the plant. Figure 7 depicts the relationship between the loading of the power plant, the efficiency loss (top) and the efficiency (bottom), respectively.

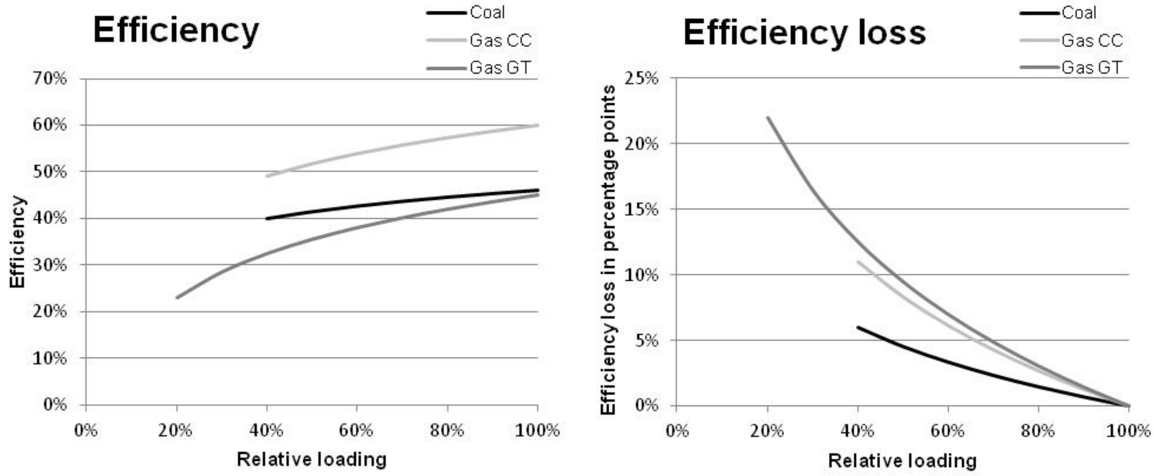

Figure 7: Efficiency loss and efficiency in part load operation.
Source: Own illustration

Table 28 lists the values on efficiency losses found in different studies. The values describe the loss of efficiency when the respective generation technology is operated at their minimum load. The units are different among the listed references and are either absolute (percentage points) or relative terms (percentage).

Efficiency loss at minimum load in percentage points (%pt) or percentage (%)

	Nuclear	Coal New SuperC	Coal Old SubC	Lignite New	Lignite Old	Gas CC	Gas GT	Gas ST	Oil
Meibom 2008 p.122 table 33	-	2 %pt	-	-	-	8 %pt	21 %pt	-	-
(Grimm 2007) p. 9 *	5 %	-	4 %	-	10 %	9 %	20 %	-	-
(Klobasa et al. 2009) p.30	-	-	4 %	-	10 %	5 %	20 %	-	-
(dena 2005) p. 280	5 %pt	-	6 %pt	-	5 %pt	11 %pt	22 %pt	-	-

Table 28: Efficiency loss parameters.
Source: Own compilation

New technologies to increase power plant flexibility

With increasing amounts of intermittent energy resources, power plants are run in shorter cycles of start-up and shutdown. They are increasingly confronted with the necessity of more frequent start-ups and cycling, combined with decreased full load hours. As this involves higher amounts of money spent on start-up and cycling, measures to increase flexibility and decrease costs gain significance. Some measures are listed below:

- Delaying cooling down of boilers: In order to conserve warm- and hot-start conditions as long as possible, auxiliary steam may be used to heat the main steam generator during standstill. As major heat losses occur through the chimney, a stack damper may further help limiting heat loss during shutdown (PennEnergy 2010). Cooling down of the boiler can also be delayed by the use of gland water which reduces steam leakage and air ingress by sealing steam in the turbine. Steam leakage would require more start-up procedures. A Siemens report explains how the described measures delay the cooling down of the boiler and thus increase the maximum possible standstill periods during which criteria for hot and warm starts still apply (Grumann et al. 2010; Henkel et al. 2008). All of these measures are implemented in Sloe Centrale (NL), Knapsack (DE), Hamm-Uentrop (DE), and Timelkam (AT) among other plants.
- Air cooling in gas turbines: In advanced power plant types, such as the CCGT plant in Irsching (DE), using air rather than steam cooling for internal gas turbine components is reported to bring additional improvements to start-up times, with lower complexity in engine and plant leading to more flexible operation. However, air cooling lowers the overall efficiency rate since the cooling air is somewhat 'stolen' from the gas turbine (PennEnergy 2010).
- Heat-Recovery Steam Generator (HRSG): Given the aim of reducing ramping times, it is crucial to increase the load gradient of the HRSG, if available. Thermal stress in the high-pressure drum walls limits the rate of conventional HRSG and plant startup. Improvements can be achieved by means of a throughput evaporator at the high-pressure level (KW 21 2008). The CCGT power plant in Cottam (UK) is one example where such a technology is implemented with a new steam collector with separator and a new feed water management system. An alternative concept is used at Sloe Centrale (NL): A Benson type once-through HRSG eliminates the need for start-up drums, which are a limiting factor for start-up times due to thermal stress exposure (Grumann et al. 2010).
- Control technology: Further measures for increased ramping flexibility include improvements of regulation systems, i.e. simulation and monitoring. Increasing the degree of automation is generally beneficial to cycling speed. For instance, fully automated drains and vents avoid operator interferences and thus accelerate start-ups and load changes (Henkel et al. 2008).
- Parallel loading of gas and steam turbine during start-up: In old combined cycle plants, gas turbines interrupt the start-up ramping procedure at a certain hold-up point in order to wait for steam turbine synchronization. Improved monitoring and controlling systems can hold temperature gradients within limits acceptable for all critical plant components. They improve start-up times by allowing for parallel start-up of steam and combustion turbines (Grumann et al. 2010). A further measure is the use of high capacity attemperators in combined cycle plants. These allow for temperature reductions of gas turbine flue gas to the requirements of steam turbines, which allows for uncoupled start-ups of gas and steam turbine (Henkel et al. 2008).
- Reduce minimum load: Innovative auxiliary boilers are used as measures to reduce the minimum load levels of power plants and thereby broaden the range for the provision of primary and secondary reserve energy (Zeiss 2012; Rode 2004).
- Fuel dehydration: Drying systems prior to the boiling process, such as fluidized bed dehydration are reported to contribute to faster start-up and ramping times in lignite-fired power plants (Zeiss 2012).
- Increase criticality: Within the group of steam turbine technologies, the criticality of boilers affects the flexibility of power plants. Supercritical boilers operate as once-through boilers in which the water and steam generated in the furnace water walls passes through only once (homogenous fluid) (EPA 2010). Steam is generated directly within the evaporation tubes of the boiler, not in the drums. Hence, the need for water/steam separation in drums is eliminated during operation and a simpler separator can be employed during start-up conditions (EPA 2010). As such units do not have thick-walled steam drums, their start-up times are quicker, further enhancing efficiency and plant economics (EPA 2010).

4.2 Further technical characteristics

Empirical information on the availability of power plants can be found in a report of VGB PowerTech (2011b), where VGB members have voluntarily submitted availability data of power plants in 2001-2010. Availabilities are differentiated by technology, power plant size and typology. A distinction is also made between temporal availability and energy availability factor. The latter takes into account situations of partial non-availability where some parts of a power plant block are not functioning, creating a drop in maximum production.

An equally important aspect to be considered in power market modeling is the inclusion of self-consumption rates of power plants. Self-consumption is due to the electricity consumed for operating the plant and it creates a divergence between gross and net production capacity. Fuel handling, feedwater pumps, combustion air fans, cooling water pumps, pollution control equipment and other electricity needs are the causes for self-consumption of power plants. According to Konstantin (2007), self-consumption rates slightly decrease with the size of the power plant. An overview can be found in Table 30.

The technical lifetime of power plants is primarily determined by material characteristics (e.g. oxidation and corrosion resilience, erosion) but it also depends on the use patterns of individual power plants during their lifetime. Furthermore, the applied maintenance strategy of the power plant influences the technical lifetime and may be able to extend the lifetime for instance up to 60 years for lignite power plants if regular maintenance is considered. However, for modeling reasons, most studies assume a fixed amount of years for each technology. Table 31 gives an overview of assumptions on lifetimes in different studies.

The construction time of renewable energy installations is generally very short. Similarly, gas- and oil-fired power plants can be constructed in short periods. Lignite and coal power require more prolonged up-front planning and construction periods partly for technical reasons, partly for reasons of administrative and implementation complications. Nuclear power plants expose very uncertain construction periods. Olkiluoto (FI) and Flamanville (FR) have been under permanent construction since 2005 and 2007, respectively. Mochovce (SK) is being built since the early 1980s with interruptions.

		(VGB PowerTech 2011b)*	(Traber & Kemfert 2011)	(EWI et al. 2010)	(Kunz 2012)	(IEA et al. 2010)	(dena 2008)	(ECF 2010) App A, p.5
WIND	Wind Onshore	-	-	-	-	-	~ 95%	
	Wind Offshore	-	-	-	-	-	-	
SOLAR	Solar PV	-	-	-	-	-	-	
BIOMASS	Biomass	-	-	-	-	-	90%	80%
GEO	Geothermal	-	-	-	-	-	90%	91%
HYDRO	Hydro Run-of-river	-	75% use rate	-	-	85%	~ 40%	35%
	Hydro pump storage	-	-	-	-	-	~ 97%	
NUCLEAR	Nuclear	PW 84/82.6 BW 84/82.4	86%	-	84%	85% PW 82.3% BW 73.8%	95.5%	90%
COAL	Lignite New	85.5/84.5	85%	86%	90%	85%	95.3%	85%-86%
	Coal New	86.4/84.2	82%	84%	87%	85%	91.2%	
GAS	Gas CC	-/88.6	86%	84%	91%	85%	91.4%	60%
	Gas Combustion Turbine	90.1/85.7	86%	84%	90%	85%	56.1%(!)	
	Gas Steam Turbine	88.8/87.4 (p.27)	86%	-	89%	85%	-	
OIL	Oil Combustion Turbine	90.1/85.7	84%	-	90%	85%	-	
	Oil Steam Turbine	88.8/87.4 (p.27)	84%	-	89%	85%	-	

* Averages for the period 2001-2010. The left figure is the temporal availability factor. The right figure is the energy availability factor. Oil and gas combustion and steam turbines are averaged.

Table 29: Availability rates of power plants.
Source: Own compilation.

	In % of gross capacity	(Konstantin 2007) p. 290	(Grimm 2007) p. 47	(Destatis 2012) / own estimations	(NERC 2012) p.IV-5
HYDRO	Hydro Pump Stor.	-	< 0.1	1.5 (RoR) 0.4 (Pump St.)	2
NUCLEAR	Nuclear	-	-	4.9	5
COAL	Lignite Old	4.5 - 5.5	-	6	5
	Lignite New	4.5 - 5.5	-	-	5
	Coal Old (powder)	7.5 - 8	7	6 (condens.) 8.9 (backpr.)	5
	Coal New (fluidized)	12 - 14	-	-	5
GAS	Gas CC	1.5 - 2.5	1.7	2	5
	Gas Combustion T	1	0.75	1.6 - 2.9	2
	Gas Steam Turbine	3 – 4	-	1.6 - 1.9	-
OIL	Oil Combustion T	-	-	-	0
	Oil Steam Turbine	-	-	-	0

Table 30: Self-consumption rates of power plants.
Source: Own compilation

	In years	(VGB PowerTech 2011a)	(EWI et al. 2010)	(IEA et al. 2010)	(dena 2008)	(DLR & SRU 2010)	(ECF 2010) App A, p.5
WIND	Wind Onshore	25	-	25	-	20	25
	Wind Offshore	25	-	25	-	20	25
SOLAR	Solar PV	25	-	25	-	20	25
	Solar CSP	30	-	25	-	25	30
BIOMASS	Biomass	30	-	-	-	20	30
GEO	Geothermal	-	-	40	-	30	30
HYDRO	Hydro Run-of-river	50-60	-	80	-	60	50
NUCLEAR	Nuclear	-	-	60	-	-	45
COAL	Lignite Old	35	45	40	45	-	40
	Lignite New	35	45	40	45	-	
	Coal Old	35	45	40	45	-	
	Coal New	35	45	40	45	-	
GAS	Gas CC	25	30	30	40	-	30
	Gas Combustion T	25	25	30	50	-	
	Gas Steam Turbine	25	-	30	40	-	
OIL	Oil Combustion T	-	-	-	40	-	30
	Oil Steam Turbine	-	-	-	40	-	

Table 31: Technical lifetime of power plants.
Source: Own compilation

	In years	(UK Government 2002) p. 202	(Strauss 2009) p.114	(IEA et al. 2010)	(Konstantin 2007) pp. 236-237	(ECF 2010) App. A, p.5
WIND	Wind Onshore	1	-	1	-	2
	Wind Offshore	1	-	1	-	2
SOLAR	Solar PV	1	-	1	-	1
	Solar CSP	1	-	1	-	3
BIOMASS	Biomass	1	-	1	-	2
GEO	Geothermal	1	-	1	-	4
HYDRO	Hydro Run-of-river	3	-	-	-	4
NUCLEAR	Nuclear	10	7-8	7	-	7
COAL	Lignite Old	-	4	4	2	4-5
	Lignite New	7	4	4	2	
	Coal Old	-	4	4	1.5	
	Coal New	7	4	4	1.5	
GAS	Gas CC	3	-	2	1	3-4
	Gas Combustion T	3	-	2	0.5	
	Gas Steam Turbine	3	-	2	-	
OIL	Oil Combustion T	-	-	-	-	3
	Oil Steam Turbine	-	-	-	-	

Table 32: Construction periods of power plants.
Source: Own compilation

5 Conclusions: Proposal for a Data Set on Costs for 2010-2050

This study brings together a broad range of cost estimates for renewable and conventional electricity generation. There are many academic discussions regarding the future dynamics of investment costs. As cost evolutions include many uncertainties, a detailed discussion would be beyond the scope of this report. In establishing assumptions on the evolution of costs up to 2050, we revert to those studies which we deem most relevant and which include detailed information regarding technology-specific costs.

A recent report from the Potsdam Institute PIK summarizes cost projections of all renewable energy technologies and it entails a discussion on learning and technological progress (Pahle et al. 2012, chap.3). We do not treat learning and technological progress in detail in this study but keep our projections partly in line with reduction potentials from IEA (2010).

Explanations to the proposed numbers in Table 33 can be found in the relevant paragraphs in the text above and a short reasoning is summarized here below. When picking a number, attention is given such as to make qualified best guesses rather than taking averages of the literature review. The evolution of costs up to 2050 as a product of technological progress and input cost variations is partly based on relative cost reduction rates found in the IEA (2010a) for renewable energies, CCTS and nuclear technology between 2010 and 2050. The IEA rates are less optimistic than current PRIMES assumptions regarding CCTS (26.5% versus 45.4% for Oxyfuel Hard Coal) and nuclear technology (10.8% versus 17.4%).

We provide no projection on the evolution of O&M costs as these are highly dependent on site-specific characteristics, power plant material quality and labor market particularities of individual countries, whose evolution is hard to estimate. O&M cost is therefore displayed as typical average figure for the base year 2010 only.

For relatively mature technologies such as gas and steam turbines without CCTS, the PRIMES projections are conservative with little cost cuts in future. In general, all technologies in the PRIMES model become cheaper over time, owing to technological progress and input cost reductions. Table 24 provides more details with a comparison to other studies.

In the proposed set of capital cost, we assume that mature generation technologies in the field of conventional power generation keep a stable level of capital costs at rising efficiency rates. The underlying assumption is that increasing complexity of new power plants results in higher efficiency ratings which offset cost reductions in plant construction, as also argued in FfE & IFO (2012, p.A–34). Cost reductions in plant construction may be due to increased competition in supplier markets rather than technical improvements. Increasing regulatory burden is potential upside risk for costs.[18] Relatively new technologies such as lignite BoA

[18] Amongst the various reasons for cost overruns in power plant investment projects, cumbersome license approval procedures are one of the most prominent causes. Also, environmental requirements are increasing,

plants and IGCC coal-fired plants also keep their cost level constant over time. IGCC plants are not abundant in the power sector but their embedded gasification processes are not quite new. We therefore do not anticipate significant cost reductions for IGCC. Extra capital cost for CCTS lies at 1400 EUR/kW for coal- and lignite-fired power plants in 2010. The extra cost for CCTS at gas-fired stations lies at 600 EUR/kW in 2010, in line with a detailed cost break-down in MacDonald (2011). The difference between coal and gas CCTS reflects the fact that CCTS for gas-fired stations is typically designed with smaller dimensions due to less CO_2 being captured, transported and stored (Moutet 2010). Extra CCTS cost is reduced by 20% between 2010 and 2050 for both, coal and gas-fired plants. This assumption is clearly more pessimistic than MacDonald (2011) and EC (2011), but roughly in line with considerations in EASAC (2013, p.9). Capital cost for generation 3-type nuclear power stations remains at a constant level of 6000 EUR/kW. As explicated previously, this includes construction, deconstruction, waste disposal and a risk premium but no insurance. Although recent reactor designs such as EPR are still in their early deployment phase, there remain many uncertainties which may offset any cost reductions. In our proposed figures, renewable energy capital costs decrease by the rates as set out in IEA et al. (2010), except for solar power, whose capital cost is adapted due to recent significant cost reductions. For solar power it is assumed that 2020 specific investment lies at 750 EUR/kW. The 2010 cost figure is composed of the costs of modules (1,200 EUR/kW + additional 30% BOS costs). Cost reductions of 20% follow between 2020 and 2030, 15% between 2030 and 2040 and 10% between 2040 and 2050.

Efficiency factors of power generation technologies are estimated for the whole range 2010-2050. They indicate optimal conditions at full power and refer to the most recent technology readily available. That implies “EPR” for nuclear power, ”H-type” turbines for CCGTs, “BoA” for Lignite, supercritical steam turbines for coal. Efficiency gains are estimated on our own account based on the extensive literature review provided in the previous chapters.

putting upward pressure on capital cost per se. Costs of environmentally motivated facilities (flue gas cleaning, desulphurization, de-NO_X) in large power plants make out 30% of capital cost according to Strauss (2009, p.304).

	Capital cost in 2010 EUR/kW	2010	2015	2020	2025	2030	2035	2040	2045	2050	Reduction 2010-2050 (%)
WIND	Onshore	1300	1269	1240	1210	1182	1154	1127	1101	1075	17.32%
	Offshore	3000	2868	2742	2621	2506	2396	2290	2189	2093	30.23%
SOLAR	PV	1560	950	750	675	600	555	472	448	425	72.78%
	CSP	3500	3154	2841	2560	2307	2078	1872	1687	1520	56.57%
BIO	Biomass	2500	2424	2350	2278	2209	2141	2076	2013	1951	21.95%
GEO	Geothermal	4200	3982	3775	3578	3392	3216	3049	2890	2740	34.77%
HYDRO	Pump storage or reservoir	2000	2000	2000	2000	2000	2000	2000	2000	2000	0.00%
	Run-of-river	3000	3000	3000	3000	3000	3000	3000	3000	3000	0.00%
MARINE	Wave and Tidal	5000	4608	4246	3913	3605	3322	3062	2821	2600	48.00%
NUCLEAR	Nuclear – Generation 3[19]	6000	6000	6000	6000	6000	6000	6000	6000	6000	0.00%
COAL	Coal – IGCC w/o CCTS	1800	1800	1800	1800	1800	1800	1800	1800	1800	0.00%
	Coal – IGCC w CCTS[20]	3200	3162	3124	3088	3052	3018	2984	2952	2920	8.75%
	Coal – PC w/o CCTS (Advanced/SuperC)	1300	1300	1300	1300	1300	1300	1300	1300	1300	0.00%
	Coal – PC w CCTS (Advanced/SuperC)	2700	2662	2624	2588	2552	2518	2484	2452	2420	10.37%
	Coal – PC w/o CCTS (Subcritical)	1200	1200	1200	1200	1200	1200	1200	1200	1200	0.00%
	Coal - PC w CCTS (Subcritical)	2600	2562	2524	2488	2452	2418	2384	2352	2320	10.77%
	Lignite – Advanced (BoA) w/o CCTS	1500	1500	1500	1500	1500	1500	1500	1500	1500	0.00%
	Lignite – Advanced (BoA) w CCTS	2900	2862	2824	2788	2752	2718	2684	2652	2620	9.65%
GAS	Gas CC w/o CCTS	800	800	800	800	800	800	800	800	800	0.00%
	Gas CC w CCTS	1400	1384	1367	1352	1337	1322	1308	1294	1280	8.57%
	Gas Combustion Turbine w/o CCTS	400	400	400	400	400	400	400	400	400	0.00%
	Gas Combustions Turbine w CCTS	1000	984	967	952	937	922	908	894	880	12.00%
	Gas Steam Turbine w/o CCTS	400	400	400	400	400	400	400	400	400	0.00%
OIL	Oil Combustion Turbine w/o CCTS	400	400	400	400	400	400	400	400	400	0.00%
	Oil Steam Turbine w/o CCTS	400	400	400	400	400	400	400	400	400	0.00%

Nuclear includes decommissioning and waste disposal. Costs for CCTS reported in 2010 although technology was not readily available for large-scale application.

Table 33: Capital cost – proposal.

Source: Own compilation

[19] Note that nuclear capital cost includes decommissioning and waste disposal.

[20] CCTS operation and maintenance costs include the cost of carbon transportation and storage.

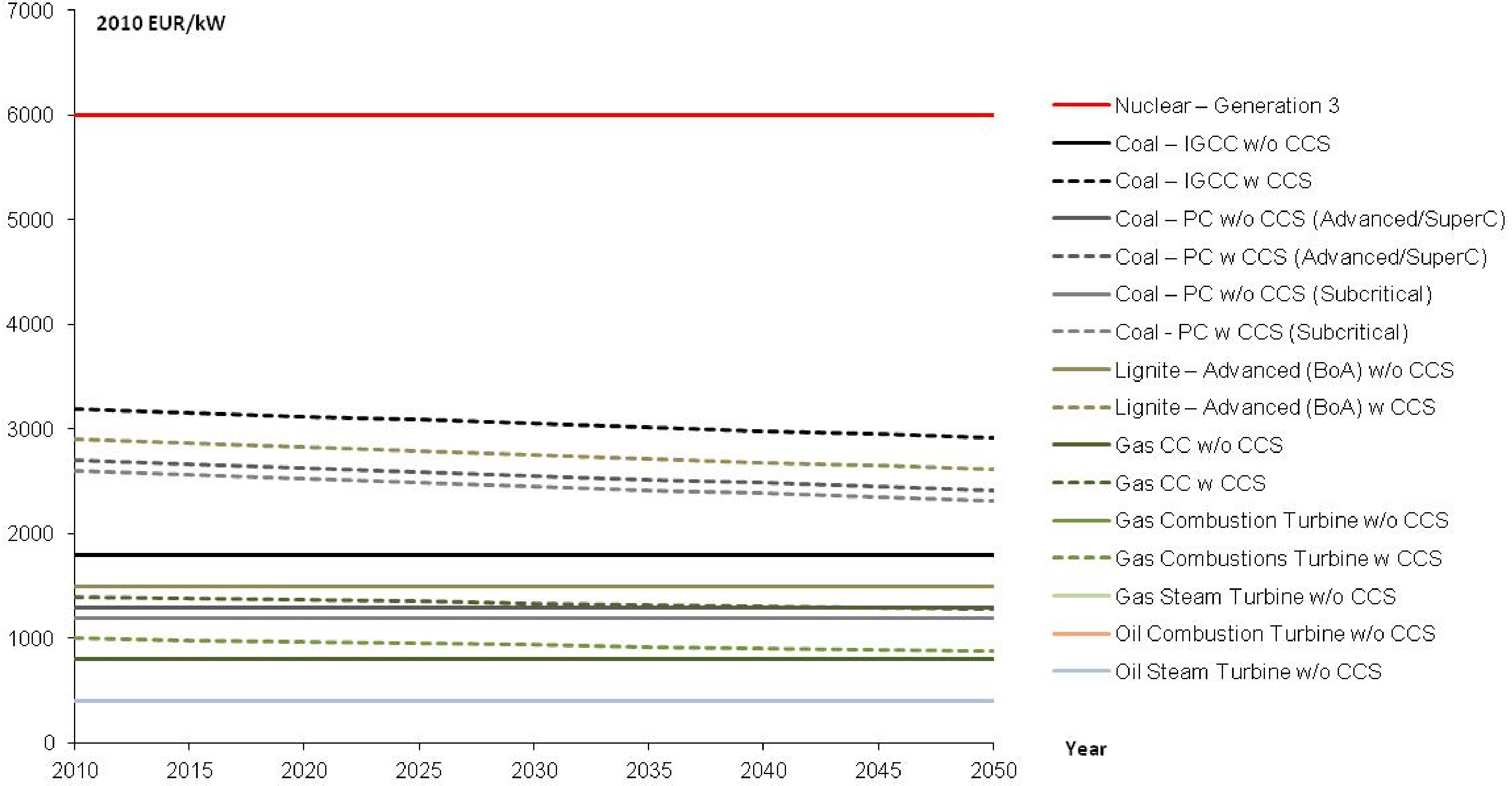

Figure 8: Capital cost evolution for conventional technologies.

Source: Own illustration

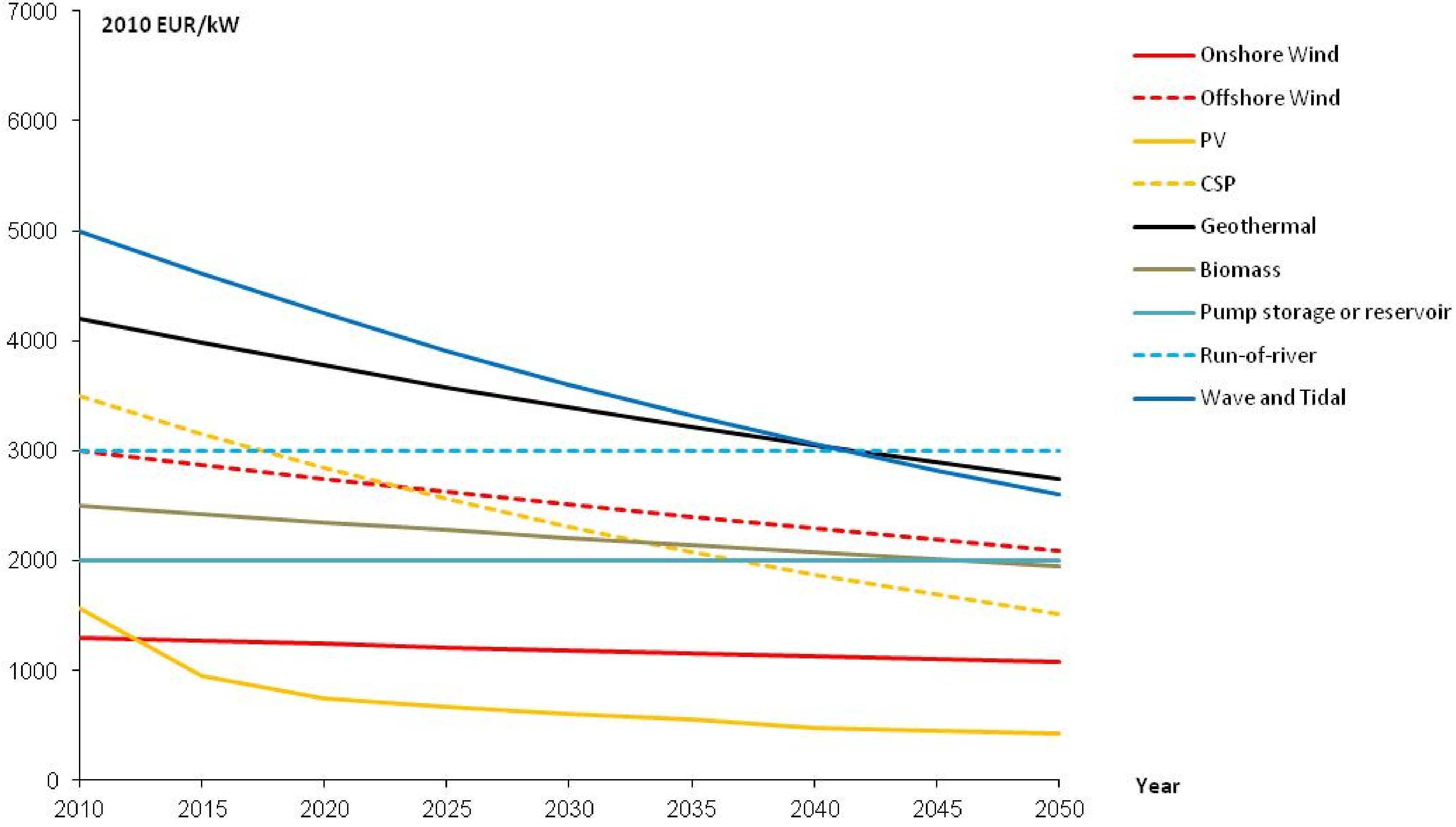

Figure 9: Capital cost evolution for renewable energies.

Source: Own illustration

		Variable O&M cost in 2010 EUR/MWh*	Fixed O&M cost in 2010 EUR/kW/year
WIND	Onshore	-	35
	Offshore	-	80
SOLAR	PV	-	25
	CSP	-	30
BIO	Biomass	-	100
GEO	Geothermal	-	80
HYDRO	Pump storage or reservoir	-	20
	Run-of-river	-	60
MARINE	Wave and Tidal	-	150
NUCLEAR	Nuclear – Generation 3	5 - 12	-
COAL	Coal – IGCC w/o CCTS	6	60
	Coal – IGCC w CCTS	13+10+7	-
	Coal – PC w/o CCTS (Advanced/SuperC)	6	25
	Coal – PC w CCTS (Advanced/SuperC)	13+10+7	-
	Coal – PC w/o CCTS (Subcritical)	6	30
	Coal - PC w CCTS (Subcritical)	13+10+7	-
	Lignite – Advanced (BoA) w/o CCTS	7	30
	Lignite – Advanced (BoA) w CCTS	14+12+8	-
GAS	Gas CC w/o CCTS	4	20
	Gas CC w CCTS	12+4+3	-
	Gas Combustion Turbine w/o CCTS	3	15
	Gas Combustions Turbine w CCTS	12+4+3	-
	Gas Steam Turbine w/o CCTS	3	15
OIL	Oil Combustion Turbine w/o CCTS	3	6
	Oil Steam Turbine w/o CCTS	3	6

* Variable O&M cost for CCTS is composed of three figures: O&M & capture + transport + storage cost.

Table 34: Operation and maintenance cost –proposal.

Source: Own compilation

	Efficiency in %	2010	2015	2020	2025	2030	2035	2040	2045	2050
BIO	Biomass	45.0	45.5	45.9	46.4	46.8	47.3	47.8	48.2	48.7
GEO	Geothermal	23.0	23.2	23.5	23.7	23.9	24.2	24.4	24.7	24.9
HYDRO	Pump storage (round-trip efficiency)	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
	Run-of-river or reservoir	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
NUCLEAR	Nuclear – Generation 3	33.0	33.2	33.3	33.5	33.7	33.8	34.0	34.2	34.3
COAL	Coal – IGCC w/o CCTS	48.0	48.5	49.0	49.5	49.9	50.4	51.0	51.5	52.0
	Coal – IGCC w CCTS	38.0	38.4	38.8	39.2	39.5	39.9	40.3	40.7	41.1
	Coal – PC w/o CCTS (Advanced/SuperC)	46.0	46.1	46.2	46.3	46.4	46.5	46.6	46.6	46.7
	Coal – PC w CCTS (Advanced/SuperC)	31.0	31.3	31.6	31.9	32.3	32.6	32.9	33.2	33.6
	Coal – PC w/o CCTS (Subcritical)	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
	Coal - PC w CCTS (Subcritical)	28.0	28.3	28.6	28.8	29.1	29.4	29.7	30.0	30.3
	Lignite – Advanced (BoA) w/o CCTS	43.0	43.4	43.9	44.3	44.7	45.2	45.6	46.1	46.6
	Lignite – Advanced (BoA) w CCTS	30.0	30.3	30.6	30.9	31.2	31.5	31.8	32.2	32.5
GAS	Gas CC w/o CCTS	60.0	60.2	60.5	60.7	61.0	61.2	61.5	61.7	61.9
	Gas CC w CCTS	48.0	48.5	49.0	49.5	49.9	50.4	51.0	51.5	52.0
	Gas Combustion Turbine w/o CCTS	39.0	39.1	39.2	39.2	39.3	39.4	39.5	39.5	39.6
	Gas Combustions Turbine w CCTS	31.0	31.3	31.6	31.9	32.3	32.6	32.9	33.2	33.6
	Gas Steam Turbine w/o CCTS	41.0	41.1	41.2	41.2	41.3	41.4	41.5	41.6	41.7
OIL	Oil Combustion Turbine w/o CCTS	39.0	39.1	39.2	39.2	39.3	39.4	39.5	39.5%	39.6
	Oil Steam Turbine w/o CCTS	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0

Table 35: Efficiency factors – proposal.

Source: Own compilation.

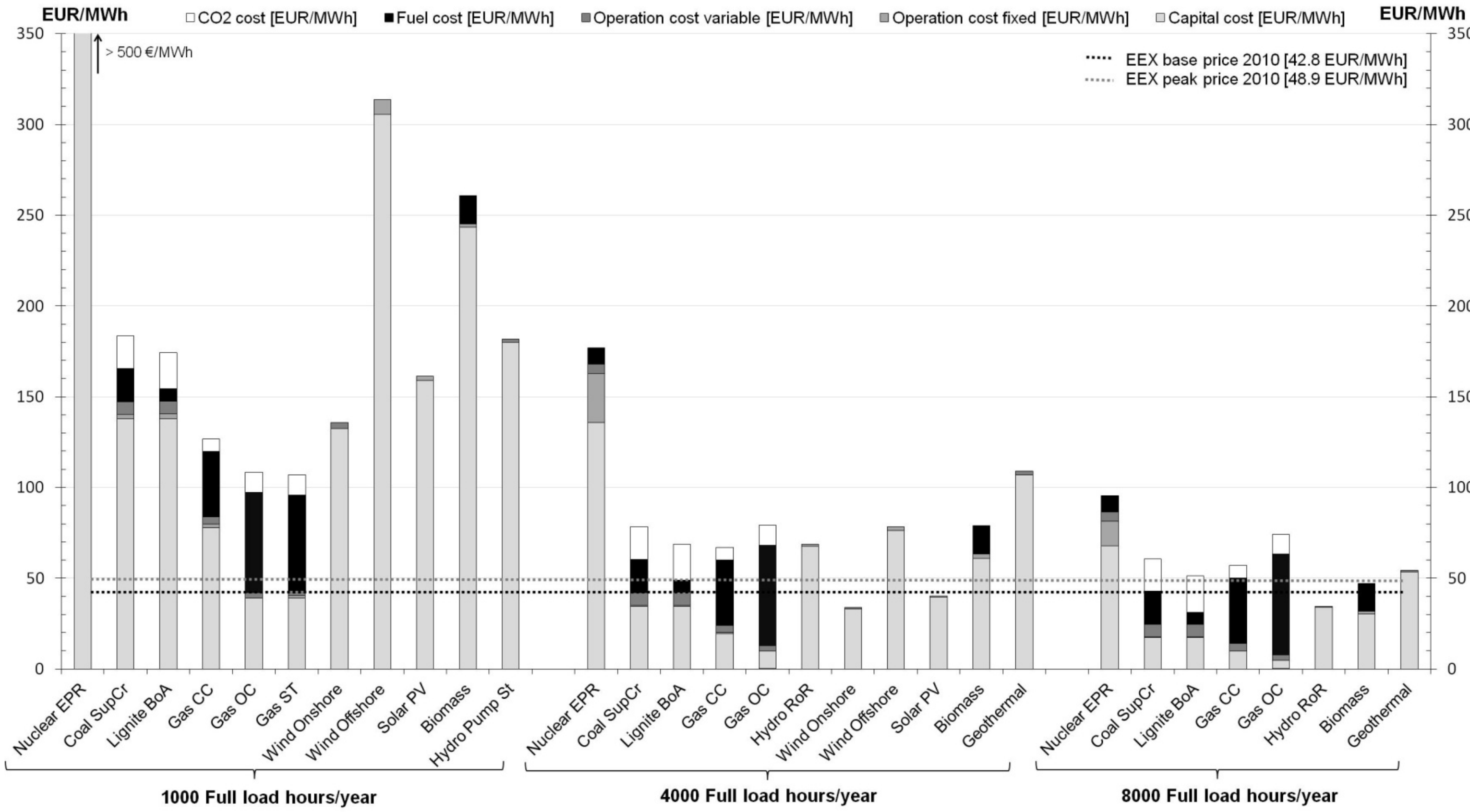

Figure 10: Levelized cost of electricity in dependence of full load hours at 2010 cost.

Source: Own illustration.

The graph plots all-in costs and their composition in dependence of full load hours. EEX prices help to identify the range at which power plants would be profitable. Even at high use factors, power plants hardly generate profits from “energy-only markets” under 2010 EEX prices. Nuclear power is not competitive in any case, with all-in-costs of around 100 EUR/MWh at 8000 full load hours. Wind Onshore and Hydro are the cheapest renewable energy options. Values in the figure are based on 2010 fuel prices (IEA 2011b). In EUR/MWh, fuel costs figure at 3 for Uranium, 7 for biomass, 21.6 for gas (7.5 $/MBtu), 8.4 for coal (99 $/t) and 2.9 for lignite (10 $/t) with CO_2 prices at 20 EUR/t. A 9% discount rate is assumed, lifetimes are as outlined in Table 31.

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