Subsidies and costs of EU energy

Annex 4-5

Contents

Annex 4 Costs

A4.1 Detailed methodology

This section starts with an overview of the main assumptions made for the levelised cost calculations. Next, the detailed methodological approaches are presented, including explanations of the special treatment of domestic heating technologies.

Table A4-1: Overview of assumptions made for calculating levelised cost.

Type	Topic	Assumption
G	Taxes and subsidies	Taxes (including value added tax) have been excluded.
G	Overnight cost	To calculate total investments costs, the overnight investment costs are equally distributed over the construction period and an interest rate of 5% is applied during the construction period.
G	Decommissioning cost	Decommissioning cost equals 15% of the capital overnight costs for nuclear energy, and zero for all other technologies - given the low impact on LCOE.
T	Transmission and distribution cost for combusted fuels	Transport and distribution cost are included for all wholesale and domestic fuel consumption.
T	Renewable technologies: Balancing and transport and distribution costs	Balancing cost[1] and costs associated with the expansion of the grid are excluded when determining the levelised cost of renewable technologies. For offshore wind production however, both the cost with and without the cost of the offshore transport and distribution network (excluding balancing cost) are provided.
T	Waste to energy (CHP) plants: Fuel cost	Waste is assumed to be have zero costs and to receive no remuneration for waste processing: in reality this ranges (from installation to installation) from negative costs (where necessary waste-treatment by incineration results in energy production) to positive costs, where waste is transported to waste-plants dedicated to energy production (and not constructed from a waste-treatment perspective).
T	Biomass CHP: fuel prices	Biomass fuel input (e.g. residues from wood, pulp and paper industries) is assumed to have zero costs.
T	PV: capital cost	To reflect the impact of the rapid decline in solar PV system prices, for PV both the levelised cost in 2008 (based on 2008 system prices) and 2012 (based on 2012 system prices) are shown.
T	CHP: determination of the revenues from electricity and heat as by-product	For the calculation of LCOH-CHP, the average wholesale price of electricity (over 2008-2012) is used to calculate the revenues from electricity production. For the calculation of LCOE-CHP, a heat price is assumed based on the natural gas price for utilities, divided by a typical boiler efficiency of 90%.

[1] Balancing cost remains a very small component of the levelised cost of wind energy in the period 2008-2012: At an average 10% annual wind energy production, balancing costs are in the range of 0.2-3.4 €$_{2009}$/MWh in different regions of Europe. Source: European Wind Energy Association (2009). Economics of Wind Energy. Available online at: http://www.ewea.org/fileadmin/ewea_documents/documents/00_POLICY_document/Economics_of_Wind_Energy__March_2009_.pdf

Type	Topic	Assumption
T	CHP: revenues from sales of heat/electricity as by-products	It has been assumed that all produced heat is sold.
T	Residential heating technologies: climate zones and capital cost	The approach for domestic heating technologies differs in the sense that in contrast to the other technologies, different climate zones and capital cost in Europe are taken into account. A more detailed explanation is given in Annex 4.
T	Nuclear power	The cost of nuclear power generation is based on Generation II reactors: Most Generation III reactors are not operational and only cost estimates are available for Europe.
T	Nuclear: fuel cost	Nuclear fuel prices are based on fuel cycle costs, assuming a conversion efficiency of 33%. Included are the front-end (Uranium mining and milling, conversion, enrichment and fuel fabrication) and back-end (spent fuel transport, storage, reprocessing and disposal) costs of the nuclear fuel cycle (see IEA, 2010)
G= Generic assumption: is valid for all technologies. T = Technology-specific assumption: valid for certain technologies only		

A4.1.1 Levelised cost of electricity

The formula to calculate the LCOE in € $_{2012}$/MWh$_e$ is:

$$LCOE = \frac{\alpha I + OM + F}{E} \quad (1)$$

where:

$$\alpha = \frac{r}{1-(1+r)^{-L_T}} \quad (2)$$

$$I = \frac{C}{L_B}\sum_{t=1}^{L_B}(1+i)^t * \left(1+\frac{d}{(1+r)^{L_T}}\right) \quad (3)$$

$$OM = FOM + (VOM - REV + d_v) * E \quad (4)$$

$$E = P \times FLH \quad (5)$$

$$F = FC * \frac{E}{\eta_E} \quad (6)$$

Table A4-2: Explanation of parameters used in formulae for levelised cost calculation

Parameter	Explanation
α	Capital recovery factor
r	Weighted average cost of capital (WACC)
I	Investment costs, including finance cost for construction at interest i
C	Capital costs, excluding finance cost for construction ('overnight cost')
OM/FOM/ VOM/REV	Net annual operation and maintenance costs; summarizing fixed OM (FOM), variable OM (VOM), and variable by-product revenues (REV)
E	Energy (electricity) produced annually, which is calculated by multiplying the electrical capacity by the number of (equivalent) full load hours (FLH)
H	Energy (heat) produced annually, which is calculated by multiplying the heat capacity by the number of (equivalent) full load hours for heat
F	Annual fuel costs
FC	Fuel costs per unit of energy input
i	Interest rate over the construction loan
L_T	Project duration (in operation)
L_B	Construction period
d	Decommissioning cost factor (relevant for nuclear technologies only – set at 15%)
FLH_E / FLH_H	Equivalent full load hours for, respectively, electricity and heat production
η_E / η_E	Conversion efficiency (in lower heating value – LHV) of electricity and heat generation
HP	Heat price a CHP installation receives for heat production as by-product
EP	Electricity price a CHP installation receives for electricity production as by-product

A4.1.2 Levelised cost of heat

The approach for determining LCOH is analogous to the approach followed for determining LCOE. In contrast to the LCOE calculations, for all domestic heating technologies, capital costs are differentiated based on five climate zones defined for Europe – a more elaborate explanation is provided at the end of this section. However, for the industrial steam boiler EU-wide capital costs are used as shown in Figure A4-1.

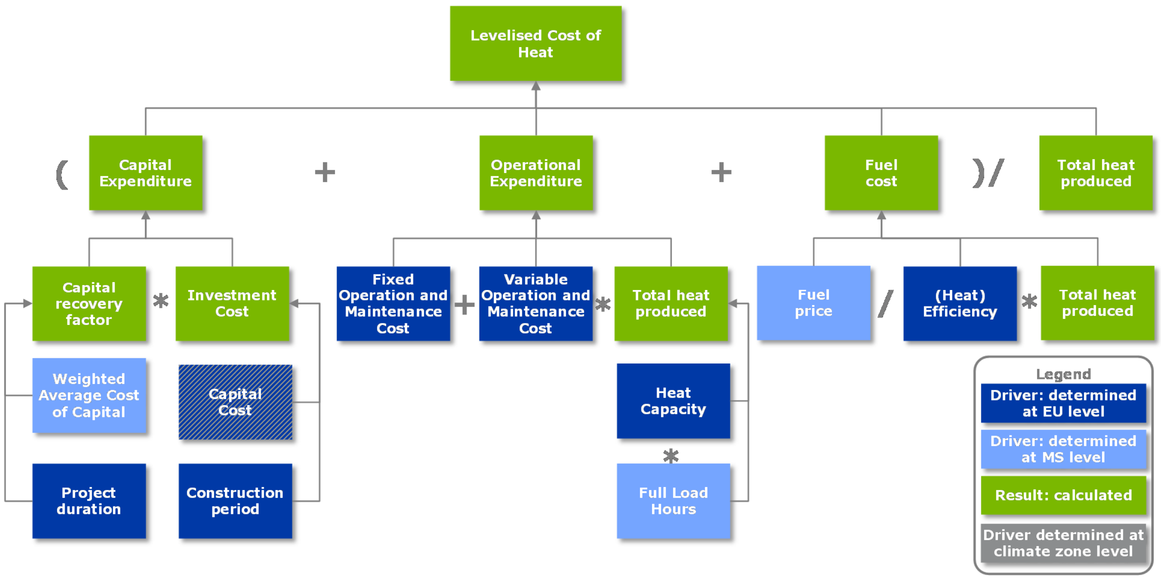

Figure A4-1: Simplified overview of approach followed and drivers determining the LCOH

The formula to calculate the LCOH in € $_{2012}$ is:

$$LCOH = \frac{\alpha I + OM + F}{H} \quad (1)$$

where:

$$I = \frac{C}{L_B} \sum_{t=1}^{L_B} (1+i)^t \quad (2)$$

$$OM = FOM + VOM * H \quad (3)$$

$$F = FC * \frac{H}{\eta_H} \quad (4)$$

Residential heating technologies

The approach for residential heating technologies differs in the sense that in contrast to the other technologies, different climate zones and capital costs in Europe are taken into account.

To calculate LCOH of different domestic heating systems, technical and economical parameters were derived or collected. This was done for five domestic heating technologies and for two building types per technology (single family and multi-family) in five European climate zones selected (in accordance with Ecofys, 2013a[2]), taking into account different thermal standards in each of the climate zones (based on Ecofys, 2013b). Each European MS was assigned to one of the five climate zones in accordance with the Ecofys-BEAM model[3] (Ecofys, 2013b)[4].

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[2] Ecofys (2013a) Towards nZEB. Definition of common principles under the EPBD http://www.ecofys.com/en/publication/towards-nearly-zero-energy-buildings.

[3] Note that in practice, multiple climate zones may be relevant for a single country.

[4] Ecofys (2013b) Heat Pump Implementation Scenarios until 2030: http://www.ecofys.com/en/publication/heat-pump-implementation-scenarios-until-2030

Table A4-3: Climate zones, in brackets the city for which data from the climate zone is derived, and allocation of Member States to climate zones.

Climate zone	Member states allocated to climate zone
Northern Europe (Stockholm)	Finland, Latvia, Sweden, Estonia, Lithuania
Eastern Europe (Bratislava)	Slovakia, Hungary, Slovenia, Austria, Romania, Bulgaria
Southern Europe (Palermo)	Greece, Cyprus, Italy, Malta
(South-) Western Europe (Madrid)	Portugal, Spain, Croatia
(West-) Central Europe (Paris)	Netherlands, Germany, Belgium, Denmark, Ireland, United Kingdom, France, Czech Republic, Poland, Luxembourg

The Ecofys BEAM-model and the Passive House Planning Package (PHI, 2013)[5] simulated the heating demand and installed capacity so that full load hours could be calculated for each case. Specific investment costs (Ecofys, 2013b) of the heating systems have been converted by country factors (derived from BKI, 2012)[6] to account for regional cost differences. Finally operating costs and lifetimes of the heating systems have been determined according to the German implementation of the EN 154594 (DIN, 2008)[7].

A4.1.3 Levelised cost of CHP

In case of electricity from CHP, generation costs are similar to the calculation for plants that only produce electricity or heat. The only difference is that potential revenues from heat sales are subtracted from the electricity generation costs, as shown in the subsequent overview.

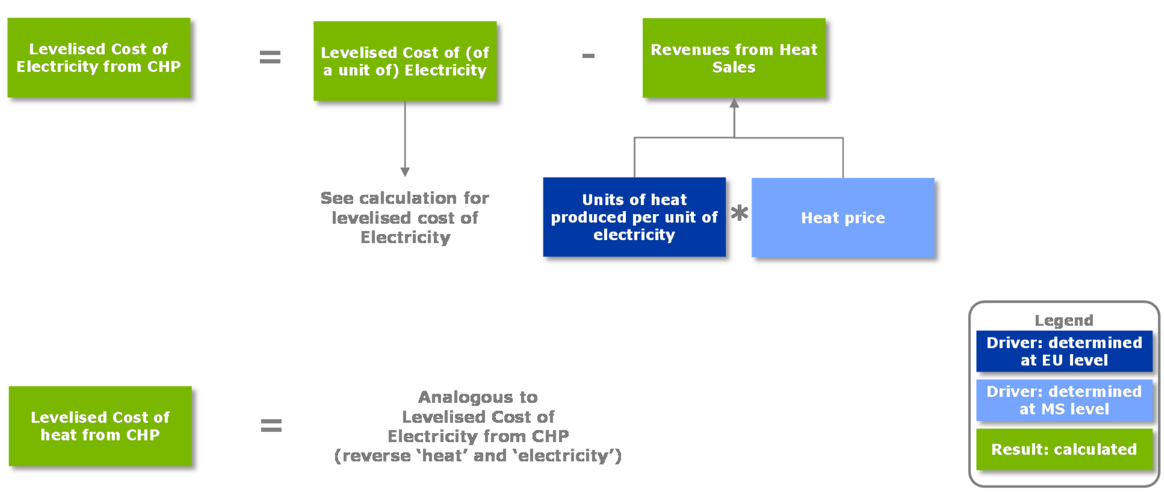

Figure A4-2: Simplified overview of approach followed and drivers determining the levelised cost of CHP

[5] Passive Housing Institute (2013). Passive House Planning Package. http://www.passiv.de/en/04_phpp/04_phpp.htm

[6] BKI (2012). Baukosten Gebäude 2012, Statistische Kostenkennwerte Teil 1 -Neubau.

[7] Deutsches Institut für Normung e.V. (2008). DIN EN 15459. Energieeffizienz von Gebäuden – Wirtschaftlichkeitsberechnungen für Energieanlagen in Gebäuden; Deutsche Fassung EN 15459:2007.

As well as calculating the cost of electricity from CHP, where heat sales are treated as revenues, we also calculate the cost of heat production, where electricity sales are treated as revenue. As there is no market price for heat, we assumed a heat price based on the natural gas price, divided by a typical boiler efficiency of 90%. The average wholesale price of electricity (over 2008 - 2012) is used to calculate the revenues from electricity production. The formula to calculate the LCOE of CHP in € $_{2012}$/MWh$_e$ is shown below. To calculate the LCOH of CHP, the same formulae can be applied, by interchanging the E and H, η_E and η_H FLH_E and FLH_H and replacing HP with EP.

$$LCOE = \frac{\alpha I + OM + F}{E} - H \times HP \times \frac{\eta_H \times FLH_H}{\eta_E \times FLH_E} \qquad (1)$$

where:

$$I = \frac{C}{L_B} \sum_{t=1}^{L_B} (1+i)^t \qquad (2)$$

$$OM = FOM + VOM * E \qquad (3)$$

$$E = P \times FLH_E \qquad (4)$$

$$F = FC * \frac{E+H}{\eta_E + \eta_H} \qquad (5)$$

A4.2 Input data at member state level

This section gives an overview of MS-specific assumptions made for the calculation of levelised cost and/or external costs.

A4.2.1 Fuel prices

This section provides an overview of the fuel prices used and the assumptions made in case of data gaps. Table A4-5 summarises the energy prices that we used in the calculation of the levelised costs. It describes the sources and assumptions per fuel. All prices were converted to € $_{2012}$.

Table A4-4: Fuel and electricity prices used for the determination of levelised cost in € $_{2012}$/GJ. (n.a. = not applicable)

Member state	Coal	electricity (domestic)	electricity (wholesale)	biomass pellets (domestic)	biomass pellets (wholesale)	natural gas (domestic)	natural gas (wholesale)
EU28 average	3.5	35	13	14	9	13	5.6
Austria	6.7	39	13	14	9	14	6.4
Belgium	3.9	44	13	n.a.	8	14	5.5
Bulgaria	3.6	20	12	n.a.	n.a.	10	8.4
Croatia	3.4	28	12	n.a.	n.a.	8	9.1
Cyprus	n.a.	58	28	n.a.	n.a.	n.a.	n.a.
Czech Republic	3.4	33	12	n.a.	n.a.	13	7.7
Denmark	3.5	36	12	14	8	14	5.7
Estonia	3.4	21	12	n.a.	n.a.	9	7.6

Member state	Coal	electricity (domestic)	electricity (wholesale)	biomass pellets (domestic)	biomass pellets (wholesale)	natural gas (domestic)	natural gas (wholesale)
Finland	3.3	29	12	14	n.a.	17	5.9
France	3.6	29	13	14	n.a.	14	5.4
Germany	3.4	40	13	14	11	13	5.7
Greece	3.7	28	14	n.a.	n.a.	14	7.5
Hungary	3.0	36	12	n.a.	n.a.	11	7.4
Ireland	3.9	52	18	n.a.	n.a.	14	5.3
Italy	3.8	42	19	14	n.a.	14	6.9
Latvia	3.0	29	12	n.a.	n.a.	11	7.3
Lithuania	3.3	26	12	n.a.	n.a.	11	8.4
Luxembourg	3.8	42	13	n.a.	n.a.	13	5.5
Malta	n.a.	44	28	n.a.	n.a.	n.a.	n.a.
Netherlands	3.2	38	13	n.a.	8	13	5.4
Poland	2.9	30	12	n.a.	n.a.	11	7.6
Portugal	3.1	33	12	14	n.a.	17	5.6
Romania	3.7	24	12	n.a.	n.a.	5	7.8
Slovakia	3.8	39	12	n.a.	n.a.	11	7.5
Slovenia	3.4	31	12	n.a.	n.a.	15	9.1
Spain	3.5	44	12	14	n.a.	15	5.8
Sweden	6.3	35	12	14	8	17	5.9
United Kingdom	3.5	43	14	n.a.	n.a.	12	5.3

Table A4-5: Overview of assumptions and sources per energy carrier

	Remarks	Sources
Coal	Prices correspond to import prices of bituminous coal and represent annual averages for the period 2008-2012 (Eurostat Comext, 2014). Transport costs are included. A transport cost premium of 0.16 €/GJ was assumed for inland shipping from the national border to location of destination based on PLANCO Consulting et al. (2007). Prices were converted from €/t to €/GJ by assuming an energy content of 25.8 GJ/t in accordance with IPCC (2012). • Prices for Slovenia are assumed equal to Croatia as they were deemed unrealistic (values of factor 100 higher than EU average).	Eurostat Comext Statistics (2014). EU Trade Since 1988 By CN8 (DS-016890). PLANCO Consulting, Bundesanstalt für Gewässerkunde. Economical and Ecological Comparison of Transport Modes: Road, Railways, Inland Waterways. IPCC (2006) Guidelines. https://www.ipcc.ch/meetings/session25/doc4a4b/vol2.pdf
Electricity (domestic)	Used for the calculation of the levelised cost of the domestic heat pumps. Electricity is used as a fuel in the calculation. Including transport and distribution, excluding all taxes and levies. Average 2008-2012 prices. For some MS, prices for some years were not available. In those cases, the average over the available years was taken. Bandwidth: 2,500 kWh < Consumption < 5,000 kWh.	Eurostat. Electricity prices components for domestic consumers, from 2007 onwards - annual data [nrg_pc_204_c] (S1). Consulted in June 2014.
Electricity	Used for the calculation of the (revenue component) of the	European Commission – DG Energy

	Remarks	Sources
(wholesale)	levelised costs of CHP technologies. Monthly average wholesale prices in 2009-2012 in regional electricity markets. Excluding all taxes and levies and transport and distribution costs. For a number of countries no data was available. For these countries prices are set equal to prices in neighbouring countries as follows: • Latvia: assumed equal to Northern European prices • Bulgaria/Croatia: assumed equal Central Eastern Europe prices • Ireland: UK prices plus a premium of 12.5 euros corresponding to the first quarter of 2012 (European Commission 2013).	(2013) Quarterly Report on European Electricity Markets Market Observatory for Energy DG Energy Volume 5, issues 3 & 4 Third and fourth quarter 2012. Electricity prices for industrial consumers, from 2007 onwards - bi-annual data [nrg_pc_205].
Biomass pellets (domestic)	This fuel is used in a domestic biomass pellet boiler. Average annual 2008-2012 prices in Germany for bags of biomass pellets excluding VAT, including transport cost (50 kilometres). Assumed valid for all members states with wood pellet consumption due to lack of reliable data at EU Member State level. Only MS with a significant domestic biomass pellet consumption have been taken into account - defined as an annual consumption higher than 250 kt in Europe based on IEA (2010) of which at least half is residential consumption according to Poyry (2010).	IEA (2010) Task 40: Sustainable International Bioenergy Trade. Global Wood Pellet Industry Market and Trust Study. Poyry (2010) multi-client study on wood pellets 2010. Website C.A.R.M.E.N http://www.carmen-ev.de/index.php. Consulted in June 2013.
Biomass pellets (wholesale)	We assumed that this fuel is used in dedicated biomass power plants. If not already included and transport cost (200 km per truck; at 15 €/tonne) have been added. VAT has been excluded.	Deutsches Biomasse ForschungsZentrum (2012) Kurzstudie Preisentwicklung von Industriepellets in Europa. Website C.A.R.M.E.N http://www.carmen-ev.de/index.php http://www.rhincentive.co.uk/library/regulation/100201Biomass_prices.pdf http://www.foex.fi/uploads/bioenergy/PIX_Nordic_Pellet_History.pdf. All consulted in June 2014
Natural gas (domestic)	Used in domestic gas-fired heating technologies. Average 2008-2012 prices. For some MS, prices for some years were not available. In those cases, the average over the available years was taken. Including transport and distribution costs, excluding all taxes and levies. Bandwidth: 20 GJ < Consumption < 200 GJ • Finland: no data available in Eurostat, assumed equal to SE.	Eurostat Gas prices for domestic consumers, from 2007 onwards - bi-annual data [nrg_pc_202]. Consulted in June 2014.
Natural Gas (wholesale)	Natural gas prices are average regional monthly prices from Europe's hubs (European Commission, 2010-2013). All taxes and levies are thus excluded. Transport and distribution costs have been included. These costs are	European Commission (2010-2013). DG Energy, Quarterly Report On European Gas Markets. Market Observatory For Energy:

	Remarks	Sources
	based on the average cost paid by large scale industrial ammonia plants in Europe which are expected to consume comparable orders of magnitudes of natural gas. Therefore, they are likely to have comparable economies of scale with regard to transport and distribution costs. A cost of 0.23 €/GJ is assumed (European Commission, 2014). Note that for countries for which fuel price information was unavailable (typically countries with relatively little gas consumption by utilities), prices are set equal to prices in neighbouring countries: • Ireland: assumed equal to UK • Poland: No intervention-free prices are available as prices are regulated by government, almost all Polish gas comes from Russia. Assumed equal to SK, HU and CZ. • Croatia: assumed equal to SL • Denmark, Finland, Sweden: Assumed equal to DE • Malta/Cyprus: zero utility/industrial scale natural gas consumption, therefore no price available.	• Volume 3, Issue 4: October 2010 – December 2010. • Volume 4, issue 4: October 2011 – December 2011 • Volume 5, issue 1: January 2012 – March 2012 • Volume 6, issue 2 • Second quarter 2013. Country data from EIA. http://www.eia.gov/countries/country-data.cfm?fips=cy European Commission, 2014. Commission Staff Working Document. Energy prices and costs report. http://ec.europa.eu/energy/doc/2030/20140122_swd_prices.pdf

A4.2.2 Full load hours

This section provides an overview of both the technical and actual full load hours. Full load hours do not indicate the hours a technology has been operational, but represent the equivalent hours a technology runs at full capacity to generate a certain amount of electricity. Full load hours are equivalent to capacity factors: a capacity factor of 85% is equivalent to 85%*8760=7,446 full load hours.

Technical full load hours

For electricity generation, we also present results based on technically possible full load hours (FLHs). These FLH will not be achieved on average when studying a whole power system, although baseload technologies such as nuclear power can achieve high utilisation levels that are close to the technical maximum. The technical full load hours indicate the minimum cost level that could be achieved for a certain technology. Note that technical full load hours could be slightly higher or lower. For example: the IEA uses a capacity factor of 0.85, which corresponds to 7,446 hours for thermal power generation, while a capacity factor of 0.9 could be achieved for individual installations. Therefore, the difference between a capacity factor of 0.85 (e.g. coal power) and 0.9 (e.g. hydropower) is not a significant difference. For hydropower, the capacity factor does not take into account the resource availability (water flow), which differs from site to site. This means that in many locations, water availability (e.g. in dry seasons) might constrain the hydropower production.

Table A4-6: Summary of used technical full load hours

Technology	Annual full load hours	Source
Coal	7,446	IEA (2010)
Gas	7,446	IEA (2010)
Biomass - dedicated	7,446	IEA (2010)
Hydropower	7,884	IPCC (2011)
Nuclear	7,446	IEA (2010)
Solar PV – rooftop (2008 and 2012)	1,169	Based on JRC PVGIS[8]
Solar PV – utility (2008 and 2012)	1,169	Based on JRC PVGIS[8]
Wind onshore	1,979	Ecofys et al (2011)[91]
Wind offshore	3,590	Ecofys et al (2011) [91]
Oil	7,446	IEA (2005)
CHP Gas - electricity	7,446	Assumption, based on dedicated thermal electricity generation
CHP Coal - electricity	7,446	
CHP Waste - electricity	7,446	
CHP Biomass - electricity	7,446	
CHP Biomass - heat	7,446	
CHP Gas - Heat	7,446	
CHP Coal - Heat	7,446	
CHP Waste - Heat	7,446	
CHP Industry - Gas - Heat	8,000	Assumption

For the industrial technologies, utilisation depends more on industrial activity than on (national or regional) energy markets. Therefore, high amounts of full load hours have been assumed, also when calculating levelised cost in the MS. For domestic heating technologies the average full load hours in northern Europe is used to represent 'technical FLH'.

Actual full load hours

Electricity

The following equation was used to calculate the Full Load Hours (FLH):

$$FLH = Generation\ (MWh) / Capacity\ (MW)$$

Data on electricity generation[9] and installed electrical (non-CHP) capacity[10] was obtained from Eurostat for the years 2008-2012 for all 28 Member States and mapped to the technology categories defined above by source. For some technology categories, additional data was required to complete this mapping:

To split the capacity of combustible fuels into hard coal, lignite, gas and oil (and into CHP vs non-CHP), the Platts Database[11] was used to compute percentages of combustible fuels per technology and country. For hydropower, wind power and electricity from PV solar panels alternative approaches are applied:

- Hydropower: Hydro was split into *run of river* and *reservoir* with data from 2010 and 2011 as data from 2012 was not available for all Member States. Because Eurostat did not provide a

[8] http://re.jrc.ec.europa.eu/pvgis/
[9] Eurostat Table nrg_105a
[10] Eurostat Table nrg_113a
[11] World Energy Power Plant Database 2014

consistent dataset, EURELECTRIC data statistics were used (both capacities and production) to calculate FLH.[12] EURELECTRIC data also contains some gaps, consequently the calculated FLH have uncertainties.

- PV: Average FLH per MS originating from a European Commission GIS database[13]. FLH represent the average (between the most Northern and Southern latitude in a country) amount of FLH and assume country-specific optimal inclination and orientation. Note that for Sweden and Finland, FLH have been based on the Southern part of the country to reflect population density.
- Wind: FLH hours of onshore wind originate from the RE-Shaping project[14]. For offshore FLH for each wind farm are estimated based on the relationship[15] between wind speed and typical park performance. The average annual wind speed for all European operational wind farms operating by the end of 2012 originate from the Northern Seas Wind Index Database Norsewind wind atlas[16]. In case multiple wind parks were existing per country, FLH hours are averaged per country based on the respective installed capacities of the different parks.

The average FLH of the period 2008-2012 were used to calculate the full load hours. If for a technology and/or a Member State fewer years were available, we used the available years.

<u>CHP</u>

Full load hours of CHP were based on production and capacities indicated in Eurostat Combined Heat and Power (CHP) data[17]. Since 2011 was the latest available year, the average FLH between 2008 and 2011 is used in this study. We estimated both FLH based on heat production as well as electricity production. The CHP data is used for all fuel types, if according to the statistics, a MS does not produce CHP electricity or heat with a certain fuel, the FLH for CHP with that particular fuel is set to zero.

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[12] EURELECTRIC, 2014. Power Statistics & Trends - 2013 Edition. EURELECTRIC, Brussels

[13] European Commission - JRC, CMSAF. Photovoltaic Geographical Information System - Interactive Maps. Online available at: http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php Consulted in July 2014.

[14] Ecofys et al (2011). D10 Long Term Potentials and Costs of RES Part I: Potentials, Diffusion and Technological learning. Available online at: http://www.reshaping-res-policy.eu/downloads/D10_Long-term-potentials-and-cost-of-RES.pdf

[15] This relationship can be found in: European Topic Centre on Air and Climate Change (2008). Wind-energy potential in Europe 2020 - 2030. Available online at: http://acm.eionet.europa.eu/docs/ETCACC_TP_2008_6_ren_wind_energy_Europe.pdf

[16] More specifically, the combined 'Focus Area 2' and 'SAR' datasets from http://www.norsewind.eu/ Consulted in July 2014, are used.

[17] Eurostat, 2013. Combined Heat and Power (CHP) data 2005-2011. Excel file. Last updated: 11 June 2013. Available at:

Table A4-7: Overview of full load hours and technical lifetimes used in the levelised costs calculations

Technology	Technical lifetime	Full Load Hours																											
		EU28	AT	BE	BG	HR	CY	CZ	DK	EE	FI	FR	DE	EL	HU	IE	IT	LV	LT	LU	MT	NL	PL	PT	RO	SK	SI	ES	SE	UK
Hard coal	40	4,318	5,773	2,594	2,388	2,464	0	2,524	0	0	2,281	2,196	3,905	0	2,842	5,268	4,479	0	0	0	0	4,393	0	4,997	0	0	0	3,910	0	4,144
Natural gas	30	1,865	4,515	4,328	0	917	0	1,049	0	0	407	2,902	4,283	2,821	1,354	4,036	1,919	0	0	3,532	0	2,233	0	2,774	2,601	680	17	2,732	0	5,494
Biomass pellets dedicated	40	4,425	4,308	3,870	n.a.	n.a.	n.a.	n.a.	557	n.a.	n.a.	n.a.	6,209	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	2,983	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0	5,637
Geothermal	30	7,744	1,500										3,114				7,744							7,464						
Hydropower - Dam	50	3,005	0	0	1,216	0	0	0	0	0	0	1,166	907	2,156	0	0	2,934	0	0	0	0	0	4,959	2,464	2,851	0	0	2,376	4,115	0
Hydropower - Run-of-river	50	3,748	4,844	2,112	2,004	0	0	3,986	0	0	4,036	3,616	6,071	3,494	4,000	3,153	4,315	1,999	4,310	0	0	2,632	2,173	3,154	0	0	0	5,167	0	3,038
Nuclear	60	6,785	0	7,404	7,740	0	0	6,788	0	0	8,201	6,467	6,480	0	7,362	0	0	0	0	0	0	7,584	0	0	7,487	7,207	6,496	7,554	6,289	5,525
Solar PV - rooftop (small scale) - 2012	25	1,169	958	943	1,155	1,250	1,600	965	940	0	874	1,220	989	1,510	1,135	0	1,405	0	906	947	1,580	938	949	1,495	1,140	1,026	1,160	1,385	859	839
Solar PV - ground (utility) - 2012	25	1,169	958	0	1,155	0	0	965	0	0	0	1,220	989	1,510	0	0	1,405	0	0	0	1,580	0	949	1,495	1,140	1,026	1,160	1,385	859	839
Solar PV - rooftop (small scale) - 2008	25	1,169	958	943	1,155	1,250	1,600	965	940	0	874	1,220	989	1,510	1,135	0	1,405	0	906	947	1,580	938	949	1,495	1,140	1,026	1,160	1,385	859	839
Solar PV - ground (utility) - 2008	25	1,169	958	0	1,155	0	0	965	0	0	0	1,220	989	1,510	0	0	1,405	0	0	0	1,580	0	949	1,495	1,140	1,026	1,160	1,385	859	839
Wind onshore	25	1,979	1,613	1,867	1,570	1,830	1,342	2,093	3,183	1,812	1,563	1,777	1,945	1,882	1,434	2,533	1,830	1,716	1,697	1,964	0	2,204	1,588	1,592	1,719	1,518	0	1,606	1,924	2,474
Wind offshore	25	3,590	0	4,000	0	0	0	0	3,670	0	2,300	0	3,760	0	0	3,150	0	0	0	0	0	3,680	0	0	0	0	0	0	3,200	3,560
Wind offshore - including transmission/distribution	25	3,590	0	4,000	0	0	0	0	3,670	0	2,300	0	3,760	0	0	3,150	0	0	0	0	0	3,680	0	0	0	0	0	0	3,200	3,560
Oil	25	823	686	85	0	929	3,345	356	244	3,188	130	344	2,255	3,894	655	573	447	0	0	0	3,868	0	0	520	77	0	407	3,218	28	404
CHP Gas - electricity	20	3,895	3,139	5,617	0	0	0	2,425	3,117	2,639	4,494	3,643	3,213	4,131	3,584	6,463	4,448	0	0	3,610	0	4,052	3,092	4,588	2,067	0	3,314	6,653	3,511	3,992
CHP Coal - electricity	20	3,730	3,139	5,617	0	0	0	2,425	3,117	2,639	4,494	3,643	3,213	4,131	3,584	0	4,448	0	0	0	0	4,052	3,092	0	2,067	0	3,314	6,653	3,511	3,992
CHP Waste - electricity	20	3,986	3,139	5,617	0	0	0	2,425	3,117	2,639	4,494	3,643	3,213	4,131	3,584	6,463	4,448	0	0	3,610	0	4,052	3,092	4,588	0	0	3,314	6,653	3,511	3,992
CHP Biomass - electricity	20	3,986	3,139	5,617	0	0	0	2,425	3,117	2,639	4,494	3,643	3,213	4,131	3,584	6,463	4,448	0	0	3,610	0	4,052	3,092	4,588	0	0	3,314	6,653	3,511	3,992
CHP Biomass - heat	20	3,745	3,285	5,617	0	0	0	1,675	3,150	2,284	4,478	3,644	3,038	4,038	3,338	4,723	2,992	0	0	3,610	0	3,343	2,981	3,789	0	0	3,767	4,732	4,786	5,623
CHP Gas - heat	20	3,653	3,285	5,617	0	0	0	1,675	3,150	2,284	4,478	3,644	3,038	4,038	3,338	4,723	2,992	0	0	3,610	0	3,343	2,981	3,789	1,825	0	3,767	4,732	4,786	5,623
CHP Coal - heat	20	3,589	3,285	5,617	0	0	0	1,675	3,150	2,284	4,478	3,644	3,038	4,038	3,338	0	2,992	0	0	0	0	3,343	2,981	0	1,825	0	3,767	4,732	4,786	5,623
CHP Waste - heat	20	3,745	3,285	5,617	0	0	0	1,675	3,150	2,284	4,478	3,644	3,038	4,038	3,338	4,723	2,992	0	0	3,610	0	3,343	2,981	3,789	0	0	3,767	4,732	4,786	5,623
CHP Industry - Gas - heat	20	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Industrial boiler	20	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Domestic gas-fired boiler (non-condensing) - North - Heat	20	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	n.a.
Domestic gas-fired boiler (non-condensing) - East - Heat	20	1,327	1,327	n.a.	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,327	1,327	1,327	n.a.	n.a.	n.a.
Domestic gas-fired boiler (non-condensing) - South - Heat	20	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	795	n.a.	n.a.	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Domestic gas-fired boiler (non-condensing) - West - Heat	20	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.
Domestic gas-fired boiler (non-condensing) - Central - Heat	20	1,582	n.a.	1,582	n.a.	n.a.	n.a.	1,582	1,582	n.a.	n.a.	1,582	1,582	n.a.	n.a.	1,582	n.a.	n.a.	n.a.	1,582	n.a.	1,582	1,582	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,582
Domestic gas-fired boiler (condensing) - North - Heat	20	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	n.a.
Domestic gas-fired boiler (condensing) - East - Heat	20	1,327	1,327	n.a.	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,327	1,327	1,327	n.a.	n.a.	n.a.
Domestic gas-fired boiler (condensing) - South - Heat	20	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	795	n.a.	n.a.	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Domestic gas-fired boiler (condensing) - West - Heat	20	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.
Domestic gas-fired boiler (condensing) - Central - Heat	20	1,582	n.a.	1,582	n.a.	n.a.	n.a.	1,582	1,582	n.a.	n.a.	1,582	1,582	n.a.	n.a.	1,582	n.a.	n.a.	n.a.	1,582	n.a.	1,582	1,582	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,582
Domestic woodpellet-fired boiler - North - Heat	20	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	n.a.
Domestic woodpellet-fired boiler - East - Heat	20	1,327	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Domestic woodpellet-fired boiler - South - Heat	20	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Domestic woodpellet-fired boiler - West - Heat	20	1,268	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.
Domestic woodpellet-fired boiler - Central - Heat	20	1,582	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,582	n.a.	n.a.	1,582	1,582	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Domestic Heat pump (air-water) - North - Heat	20	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	n.a.
Domestic Heat pump (air-water) - East - Heat	20	1,327	1,327	n.a.	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,327	1,327	1,327	n.a.	n.a.	n.a.
Domestic Heat pump (air-water) - South - Heat	20	795	n.a.	n.a.	n.a.	n.a.	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	795	n.a.	n.a.	795	n.a.	n.a.	n.a.	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Domestic Heat pump (air-water) - West - Heat	20	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.
Domestic Heat pump (air-water) - Central - Heat	20	1,582	n.a.	1,582	n.a.	n.a.	n.a.	1,582	1,582	n.a.	n.a.	1,582	1,582	n.a.	n.a.	1,582	n.a.	n.a.	n.a.	1,582	n.a.	1,582	1,582	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,582
Domestic gas-fired boiler (condensing) + solar thermal boiler - North - Heat	20	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	1,567	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,567	n.a.
Domestic gas-fired boiler (condensing) + solar thermal boiler - East - Heat	20	1,327	1,327	n.a.	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,327	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,327	1,327	1,327	n.a.	n.a.	n.a.
Domestic gas-fired boiler (condensing) + solar thermal boiler - South - Heat	20	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	795	n.a.	n.a.	795	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Domestic gas-fired boiler (condensing) + solar thermal boiler - West - Heat	20	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,268	n.a.	n.a.	n.a.	1,268	n.a.	n.a.
Domestic gas-fired boiler (condensing) + solar thermal boiler - Central - Heat	20	1,582	n.a.	1,582	n.a.	n.a.	n.a.	1,582	1,582	n.a.	n.a.	1,582	1,582	n.a.	n.a.	1,582	n.a.	n.a.	n.a.	1,582	n.a.	1,582	1,582	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	1,582

A4.2.3 Weighted Average Cost of Capital

This section gives an overview of the determination of Weighted Average Cost of Capital (WACC, post-tax, nominal) used in the determination of the levelised cost, which is defined as follows:

*WACC = (1-share of equity) * (1-corporate taxation rate) * Cost of Debt + Share of Equity * Cost of Equity*

where:
Cost of Equity = Risk free rate + Market Premium + Policy Risk Premium + Technology Risk Premium + Illiquidity risk premium

The WACC thus takes into account deduction of corporate tax and reflects a real value valid for 2012.

Table A4-8: Explanation of parameters used in the WACC formula

Parameter	Explanation
Risk Free Rate	Theoretical rate of return of an investment with no risk of financial loss.
Market Premium	Difference between the expected return on a market portfolio (excluding policy, technology and illiquidity premiums) and the risk-free rate.
Policy Risk Premium	Difference between expected return on a market portfolio and specific technology stemming from the risk associated to the set of relevant policy mechanisms and policy support measures effecting a specific technology in a given country (negative values reflect a positive impact on the cost of capital).
Technology Risk Premium	Difference between expected return on a market portfolio and specific technology stemming from the risk associated to a specific technology.
Illiquidity Risk Premium	Difference between expected return on a market portfolio and specific technology stemming from the lack of marketability of an investment that cannot be bought or sold quickly enough to prevent or minimise a loss.

Note that for domestic technologies (e.g. PV rooftop, or gas-fired condensing boilers), WACCs lower than for industrial parties or utilities have been assumed as:

- It is often not a choice but a necessity to install the technology for delivering basic services (e.g. boiler for supplying heat), this translates into lower discount rates as the reference for this is not an investment in another (energy) technology/project, but the cost of capital to the end-user (typically bank interest rates);
- Levels of risks are typically lower (e.g. a household boiler vs. an offshore wind park);

Table A4-9: Overview of Weighted Average Cost of Capital per technology per MS used in the calculation of levelised cost. Values are post corporate tax and nominal

Technology	EU28	BE	BG	HR	CY	CZ	DK	EE	FI	FR	DE	EL	HU	IE	IT	LV	LT	LU	MT	NL	PL	PT	RO	SK	SI	ES	SE	AT	UK
Hard coal - PC	9%	8%	10%	9%	10%	9%	8%	10%	8%	8%	8%	10%	9%	9%	8%	9%	10%	8%	8%	8%	9%	9%	9%	9%	9%	8%	8%	8%	8%
Gas - Combined Cycle	9%	8%	10%	9%	10%	9%	8%	10%	8%	8%	8%	10%	9%	9%	8%	9%	10%	8%	8%	8%	9%	9%	9%	9%	9%	8%	8%	8%	8%
Biomass - CHP	6%	7%	7%	7%	7%	6%	7%	7%	7%	6%	6%	7%	7%	7%	6%	6%	7%	6%	6%	7%	6%	6%	7%	6%	6%	6%	7%	6%	7%
Biomass - dedicated (power plant)	6%	7%	7%	7%	7%	6%	7%	7%	7%	6%	6%	7%	7%	7%	6%	6%	7%	6%	6%	7%	6%	6%	7%	6%	6%	6%	7%	6%	7%
Hydropower	6%	6%	7%	7%	6%	6%	6%	6%	6%	5%	5%	6%	6%	6%	6%	6%	6%	5%	5%	6%	6%	6%	6%	6%	6%	5%	6%	5%	7%
Nuclear (new plant)	10%	9%	11%	11%	11%	10%	9%	11%	10%	9%	9%	11%	10%	10%	9%	10%	11%	10%	10%	9%	10%	10%	11%	10%	10%	10%	10%	10%	9%
Solar PV - rooftop	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Solar PV - utility	6%	6%	7%	7%	6%	6%	6%	6%	6%	5%	5%	6%	6%	6%	6%	6%	6%	5%	5%	6%	6%	6%	6%	6%	6%	5%	6%	5%	7%
Wind onshore	6%	6%	7%	7%	6%	6%	6%	6%	6%	5%	5%	6%	6%	6%	6%	6%	6%	5%	5%	6%	6%	6%	6%	6%	6%	5%	6%	5%	7%
Wind offshore	7%	7%	8%	8%	8%	7%	7%	8%	7%	6%	6%	8%	7%	7%	7%	7%	8%	7%	6%	7%	7%	7%	7%	7%	7%	7%	7%	7%	8%
Oil fired	9%	8%	10%	9%	10%	9%	8%	10%	8%	8%	8%	10%	9%	9%	8%	9%	10%	8%	8%	8%	9%	9%	9%	9%	9%	8%	8%	8%	8%
CHP gas	9%	8%	10%	9%	10%	9%	8%	10%	8%	8%	8%	10%	9%	9%	8%	9%	10%	8%	8%	8%	9%	9%	9%	9%	9%	8%	8%	8%	8%
CHP coal	9%	8%	10%	9%	10%	9%	8%	10%	8%	8%	8%	10%	9%	9%	8%	9%	10%	8%	8%	8%	9%	9%	9%	9%	9%	8%	8%	8%	8%
CHP Waste	9%	8%	10%	9%	10%	9%	8%	10%	8%	8%	8%	10%	9%	9%	8%	9%	10%	8%	8%	8%	9%	9%	9%	9%	9%	8%	8%	8%	8%
Domestic gas-fired boiler	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Domestic wood-pellet-fired boiler	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Domestic heat pump	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Domestic solar thermal	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
CHP Industry - Gas - heat	9%	8%	10%	9%	10%	9%	8%	10%	8%	8%	8%	10%	9%	9%	8%	9%	10%	8%	8%	8%	9%	9%	9%	9%	9%	8%	8%	8%	8%
Industrial boiler	9%	8%	10%	9%	10%	9%	8%	10%	8%	8%	8%	10%	9%	9%	8%	9%	10%	8%	8%	8%	9%	9%	9%	9%	9%	8%	8%	8%	8%

Table A4-10: Risk free rates (nominal), market risk, illiquidity risk and policy risk premiums per MS

Member state	Risk Free Rate	Market Risk Premium	Illiquidity Risk Premium	Policy Risk Premium Renewable*	Policy Risk Premium Fossil	Policy Risk Premium Nuclear
Belgium	1.57%	6.0%	3.0%	1.5%	0%	0.0%
Bulgaria	1.57%	8.3%	3.0%	-3.0%	0%	0.0%
Croatia	1.57%	7.8%	3.0%	0.0%	0%	0.0%
Cyprus	1.57%	7.9%	3.0%	-3.0%	0%	0.0%
Czech Republic	1.57%	6.8%	3.0%	-3.0%	0%	0.0%
Denmark	1.57%	5.5%	3.0%	0.0%	0%	0.0%
Estonia	1.57%	#N/A	3.0%	-3.0%	0%	0.0%
Finland	1.57%	6.0%	3.0%	0.0%	0%	0.0%
France	1.57%	5.9%	3.0%	-3.0%	0%	0.0%
Germany	1.57%	5.5%	3.0%	-3.0%	0%	0.0%
Greece	1.57%	9.6%	3.0%	-3.0%	0%	0.0%
Hungary	1.57%	7.4%	3.0%	-3.0%	0%	0.0%
Ireland	1.57%	6.6%	3.0%	-3.0%	0%	0.0%
Italy	1.57%	5.6%	3.0%	0.0%	0%	0.0%
Latvia	1.57%	#N/A	3.0%	-3.0%	0%	0.0%
Lithuania	1.57%	7.9%	3.0%	-3.0%	0%	0.0%
Luxembourg	1.57%	6.0%	3.0%	-3.0%	0%	0.0%
Malta	1.57%	6.6%	3.0%	-3.0%	0%	0.0%
Netherlands	1.57%	5.4%	3.0%	0.0%	0%	0.0%
Poland	1.57%	6.4%	3.0%	-3.0%	0%	0.0%
Portugal	1.57%	7.2%	3.0%	-3.0%	0%	0.0%
Romania	1.57%	7.7%	3.0%	-3.0%	0%	0.0%
Slovakia	1.57%	6.9%	3.0%	-3.0%	0%	0.0%
Slovenia	1.57%	6.5%	3.0%	-3.0%	0%	0.0%
Spain	1.57%	6.0%	3.0%	-3.0%	0%	0.0%
Sweden	1.57%	5.9%	3.0%	0.0%	0%	0.0%
Austria	1.57%	5.7%	3.0%	-3.0%	0%	0.0%
United Kingdom	1.57%	5.5%	3.0%	3.0%	0%	0.0%

* Policy risk premiums for renewable energy are affected when support policies are (significantly) adjusted. The values in this table are in general believed to represent the investment decisions in the 2008-2012 period, even though some countries have had retro-active policy changes during this period. The most important changes were adopted in 2012 (e.g. Bulgaria, Greece, Spain), but some already in 2010 (Spain, Czech Republic).

Table A4-11: Technology risk premium per Member State

Technology	Class[18]	Technology Risk premium
Coal	Fossil	5%
Natural gas	Fossil	5%
Biomass - dedicated (power plant)	Fossil	5%
Hydropower	Renewable	3%
Nuclear (existing plant lifetime extension)	Nuclear	0%
Nuclear (new plant)	Nuclear	8%
Solar PV - rooftop	Renewable	0%
Solar PV - utility	Renewable	3%
Wind onshore	Renewable	3%
Wind offshore	Renewable	8%
Oil	Fossil	5%
CHP gas	Fossil	5%
CHP coal	Fossil	5%
CHP Waste	Fossil	5%
CHP Biomass	Fossil	5%
Domestic gas-fired boiler	Fossil	3%
Domestic wood-pellet-fired boiler	Fossil	3%
Domestic heat pump	Fossil	3%
Domestic solar thermal	Fossil	3%
Industrial gas turbine waste heat boiler	Fossil	5%
Industrial steam boiler	Fossil	5%

Below, an overview of assumptions used for the determination of the WACC is given.

Table A4-12: Assumptions and sources used for the determination of WACC

Parameter	Value	Remarks/Source
Risk free rate	1.57%	Fixed for all MS, 10 Year average German bond rate (average 2013)
Market Risk Premium	Var. per MS	Fernandez et al. (2012)[19]
Policy Risk Premium	Var. per MS, per tech	Ecofys (see also IEA-RETD, 2008)
Technology Risk Premium	Var. per techn.	Ecofys (see also IEA-RETD, 2008)
Illiquidity Risk Premium	Fixed for all MS	Ecofys (see also IEA-RETD, 2008)
Cost of Debt	5%	Average market value (several publications, information from confidential projects)
Weighted Average Cost of Capital for domestic technologies	4%	Ecofys expert estimate, based on consumer behaviour (e.g. domestic boiler, solar PV rooftop, etc.).

[18] Used for the application of relevant policy risk premium (nuclear, renewable or fossil).
[19] Fernandez et al. (2012) Market Risk Premium used in 82 countries in 2012: a survey with 7,192 answers (valid for 2012).

Parameter	Value	Remarks/Source
Corporate taxation rate	Var. per MS	Marginal corporate taxation rate. Average 2008-2012. KPMG (2014)[20].
Share of equity • renewables • fossil and nuclear	 25% 40%	Fixed for all Member States

There is no information in the public domain that describes a generic methodology and presents values for the cost of capital across Member States and energy conversion technologies. In reality finance parameters are determined by many different factors. The abovementioned approach is based on previous work (IEA-RETD, 2008), recent work by the consultant and on insights from ongoing research. The concept is consistent and aims to capture the main differences in the impacts of different finance conditions between Member States and technologies. During and after the stakeholder consultations for this study, no alternative suggestions for methodologies and/or data were received from stakeholder groups.

The cost of debt is assumed to be constant for all Member States and (utility-scale) technologies:

- No differentiation is made among Member States as the debt market is assumed to be European/international for utility-scale projects. Differences are rather company-specific than country-specific. This is confirmed by bankers. This is to a large extent also valid for (non-recourse) project finance.
- No differentiation is made among technologies, in fact reflecting on-balance financing. In project finance relatively small differences occur (e.g. 50-75 basis point differences between offshore and onshore wind projects).
- For the domestic/commercial sector and/or smaller projects the debt rate will show much bigger variations. For this sector we assume a fixed value for the WACC, which reflects consumer behaviour in most European countries.

The debt/equity ratio is also assumed to be constant for all Member States, but differentiated for renewable energy technologies on the one hand, and fossil/nuclear energy technologies on the other. In project finance the leverage is typically determined by the debt service coverage factor or ratio (DSCR), which reflects all risk factors of the project. This will differ per technology, per country. For the purpose of this study such a differentiation would add limited value.

A4.2.4 Conversion efficiencies

For a detailed explanation of conversion efficiencies please refer to Annex 3.

A4.2.5 Literature sources

The literature listed below was used to collect data on technology costs and performances. We used only cost data that were applicable to European countries.

- Asko Vuorinen (2007). Planning Of National Power Systems.
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[20] KPMG (2014), website consulted in June 2014
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- Breyer et al. (2011). Fuel-Parity: Impact Of Photovoltaics On Global Fossil Fuel Fired Power Plant Business.
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- IRENA (2012). Renewable Energy Technologies: Cost Analysis Series: Wind Power. Available at: http://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-WIND_POWER.pdf: International Renewable Energy Agency (IRENA), Abu Dhabi. 56 pp.
- IRENA (2013). Renewable Power Generation Cost in 2012: An Overview. Available at: https://www.irena.org/DocumentDownloads/Publications/Overview_Renewable%20Power%20Generation%20Costs%20in%202012.pdf: International Renewable Energy Agency (IRENA), Abu Dhabi. 88 pp.
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- NEEDS (2008). Final report on technical data, costs, and life cycle inventories of advanced fossil power generation systems. New Energy Externalities Developments for Sustainability (NEEDS), implemented by Paul Scherrer Institut (PSI) & Inst. für Energiewirtschaft & Rationelle Energieanwendung, Univ. Stuttgart (IER). Available at: http://www.needs-project.org/docs/RS1a%20D7.2%20Final%20report%20on%20advanced%20fossil%20power%20plants.pdf
- PB (2011). Electricity Generation Cost Model - 2011 Update Revision 1. Prepared by Parsons Brinckerhoff (PB) for Department of Energy and Climate Change (DECC). Available at: https://www.pbworld.com/pdfs/regional/uk_europe/decc_2153-electricity-generation-cost-model-2011.pdf

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- UK CCC (2011). Costs of low-carbon generation technologies. Prepared by Mott MacDonald, for Committee on Climate Change, London.
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- WEC (2013). World Energy Perspective - Cost of Energy Technologies. World Energy Council & Bloomberg New Energy Finance.

A4.3 Levelised cost results at MS level

The following section illustrates how the costs for individual technologies differ between EU MS. The difference in levelised cost is due to (a combination of) the following three parameters which can vary at MS level:

1. Fuel prices.
2. Weighted Average Cost of Capital.
3. Full load hours.

Note that if a technology is non-existing in a MS (e.g. gas-fired power plants in Cyprus), no levelised cost is shown. Ranges are based on actual FLH, based on statistics on capacities and production. For onshore and offshore wind and solar PV, full load hours based on national resource potentials were used.

A4.3.1 Average techno-economic data

The table below summarizes key parameters used to calculate levelised costs. Because costs and performance are related (O&M costs and efficiencies[21]) these parameters cannot directly be used to calculate minimum and maximum levelised costs: levelised costs were calculated for individual entries from literature to make sure the coupling between performance and costs was maintained. From the resulting range of levelised costs points, minimum, average and maximum levelised costs were identified.

[21] Note that efficiencies sometimes exceed 100%. This can be either because efficiencies are reported on the basis of lower heating values or it concerns heat pumps, or it concerns fossil-based technologies which partly rely on renewable input (gas-fired boiler combined with solar thermal boiler).

Table A4-13: Minimum, average and maximum capital investments, CAPEX, OPEX and efficiencies (based on lower heating value) in the EU28

	Investment costs (EUR/MW)			CAPEX (EUR/MWh)			OPEX (EUR/MWh)			Efficiency (%)		
Technology	Min	Average	Max	Min	Av.	Max	Min	Av.	Max	Min	Av.	Max
Hard coal	1,011,782	1,583,988	2,090,909	25	39	51	2	7	15	39%	45%	48%
Natural gas	466,976	880,339	1,624,675	27	51	94	1	6	19	49%	55%	60%
Oil	600,000	844,140	1,327,767	81	113	178	20	48	203	40%	43%	43%
Geothermal	1,650,850	4,643,015	6,500,222	17	48	67	14	17	30	100%	100%	100%
Hydropower - Dam	873,466	1,089,611	2,882,517	21	27	70	2	3	5	100%	100%	100%
Hydropower - Run-of-river	935,875	1,867,905	5,259,802	18	36	103	4	9	56	100%	100%	100%
Biomass dedicated	1,518,011	2,071,461	4,602,480	28	38	85	0	16	90	24%	36%	48%
Solar PV - rooftop (small scale) - 2012	1,609,579	1,694,789	1,800,000	88	93	99	13	21	30	100%	100%	100%
Solar PV - ground (utility) - 2012	980,192	1,268,619	1,268,619	65	85	85	17	22	40	100%	100%	100%
Solar PV - rooftop (small scale) - 2008	4,023,947	4,236,973	4,500,000	220	232	246	13	21	30	100%	100%	100%
Solar PV - ground (utility) - 2008	2,450,480	3,171,546	3,171,546	163	211	211	17	22	40	100%	100%	100%
Wind onshore	778,294	1,643,000	2,267,000	33	70	96	5	11	26	100%	100%	100%
Wind offshore	2,724,028	3,502,321	4,500,000	75	97	124	13	24	39	100%	100%	100%
Wind offshore - including transmission	3,517,639	4,647,024	5,812,607	97	128	160	14	25	40	100%	100%	100%
Nuclear	3,332,624	4,284,684	4,832,840	63	82	92	6	13	25	33%	33%	33%
CHP Gas - electricity	666,362	944,651	4,063,555	21	30	131	7	10	76	28%	42%	49%
CHP Coal - electricity	1,257,489	1,933,880	3,294,067	42	65	111	16	19	26	24%	32%	35%
CHP Waste - electricity	8,437,314	8,665,350	10,820,309	265	273	340	28	114	160	21%	21%	30%
CHP Biomass - electricity	1,562,188	3,642,364	5,507,966	41	96	145	4	26	62	17%	25%	65%
CHP Biomass - heat	943,354	1,196,294	4,045,832	26	34	113	2	12	48	49%	58%	78%
CHP Gas - heat	575,308	898,808	2,031,778	20	31	70	9	12	76	25%	42%	59%
CHP Coal - heat	830,417	1,046,890	1,235,275	29	37	43	9	11	14	50%	58%	64%
CHP Waste - heat	2,567,878	2,687,315	6,492,186	86	90	217	9	35	102	50%	69%	74%
CHP Industry - Gas - heat	575,308	800,678	2,031,778	8	11	29	4	6	7	36%	44%	59%
Industrial boiler	71,080	74,196	132,005	1	1	2	0	0	1	85%	101%	101%
Domestic gas-fired boiler (non-condensing) - North	220,800	290,400	360,000	10	14	17	2	3	3	80%	81%	82%
Domestic gas-fired boiler (non-condensing) - East	80,400	120,600	160,800	4	7	9	1	1	2	80%	81%	81%
Domestic gas-fired boiler (non-condensing) - South	158,400	178,200	198,000	15	16	18	3	3	4	82%	84%	85%
Domestic gas-fired boiler (non-condensing) - West	81,600	122,400	163,200	5	7	9	1	1	2	80%	81%	81%
Domestic gas-fired boiler (non-condensing) - Central	150,480	194,040	237,600	7	9	11	1	2	2	80%	81%	82%
Domestic gas-fired boiler (condensing) - North	276,000	363,000	450,000	13	17	21	3	3	4	91%	92%	93%
Domestic gas-fired boiler (condensing) - East	100,500	150,750	201,000	6	8	11	1	2	2	90%	92%	93%
Domestic gas-fired boiler (condensing) - South	198,000	222,750	247,500	18	21	23	4	4	5	92%	93%	95%
Domestic gas-fired boiler (condensing) - West	102,000	153,000	204,000	6	9	12	1	2	2	90%	92%	93%
Domestic gas-fired boiler (condensing) - Central	188,100	242,550	297,000	9	11	14	2	2	3	91%	92%	93%
Domestic woodpellet-fired boiler - North	750,000	1,200,000	1,650,000	35	56	77	7	11	16	83%	85%	86%
Domestic woodpellet-fired boiler - East	301,500	418,750	536,000	17	23	30	3	5	6	83%	85%	86%
Domestic woodpellet-fired boiler - South	528,000	717,750	907,500	49	66	84	10	14	17	84%	86%	88%
Domestic woodpellet-fired boiler - West	306,000	425,000	544,000	18	25	32	4	5	6	83%	85%	86%
Domestic woodpellet-fired boiler - Central	534,600	861,300	1,188,000	25	40	55	5	8	11	83%	85%	86%
Domestic Heat pump (air-water) - North	1,320,000	1,440,000	1,560,000	62	68	73	25	28	30	286%	293%	301%
Domestic Heat pump (air-water) - East	737,000	770,500	804,000	41	43	45	17	17	18	360%	374%	389%
Domestic Heat pump (air-water) - South	792,000	859,650	927,300	73	80	86	30	32	35	312%	332%	351%
Domestic Heat pump (air-water) - West	741,200	778,600	816,000	43	45	47	18	18	19	364%	373%	383%
Domestic Heat pump (air-water) - Central	1,089,000	1,188,000	1,287,000	51	55	60	21	23	24	360%	374%	389%
Domestic gas-fired boiler (condensing) + solar thermal boiler - North	547,078	720,544	894,009	26	34	42	4	5	6	98%	99%	100%
Domestic gas-fired boiler (condensing) + solar thermal boiler - East	193,431	265,281	337,132	11	15	19	1	2	3	97%	98%	100%
Domestic gas-fired boiler (condensing) + solar thermal boiler - South	438,395	511,880	585,366	41	47	54	5	6	7	130%	136%	142%
Domestic gas-fired boiler (condensing) + solar thermal boiler - West	195,163	264,734	334,305	11	15	19	2	2	3	98%	100%	103%
Domestic gas-fired boiler (condensing) + solar thermal boiler - Central	378,437	476,772	575,106	18	22	27	2	3	4	97%	99%	101%

A4.3.2 Hydropower – Run of River

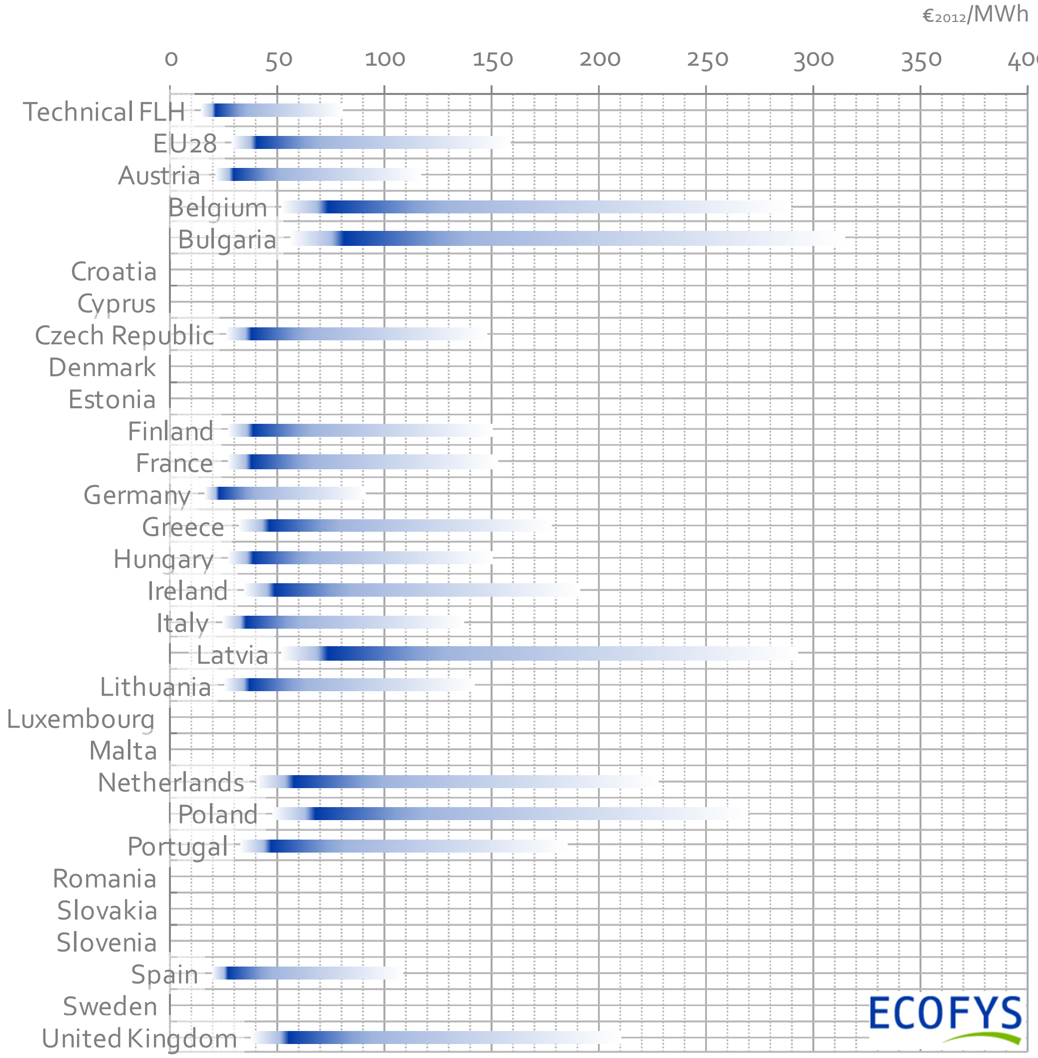

Figure A4-3: Levelised cost of electricity in the EU28 Member States for small scale hydropower. Member States to which the technology is not applicable or for which insufficient data is available are indicated on the left side of the chart.

The wide ranges occurring for a large share of the countries are caused by a wide range in investments costs combined with relatively low full load hours for some Member States. Cost differences are primarily caused by differences in full load hours.

The full load hours reported for hydropower have a large uncertainty because there is no consistent public dataset that consistently reports both installed capacity and production. Consequently, this introduces an uncertainty in the presented LCOEs.
Run-of-River plants also covers smaller hydropower (~10s MW) and this might include smaller reservoirs (e.g. Belgium).

Although hydropower production in Denmark, Estonia, Luxembourg, Croatia and Slovenia is reported, no consistent data were available on these countries.

A4.3.3 Hydropower – Reservoir

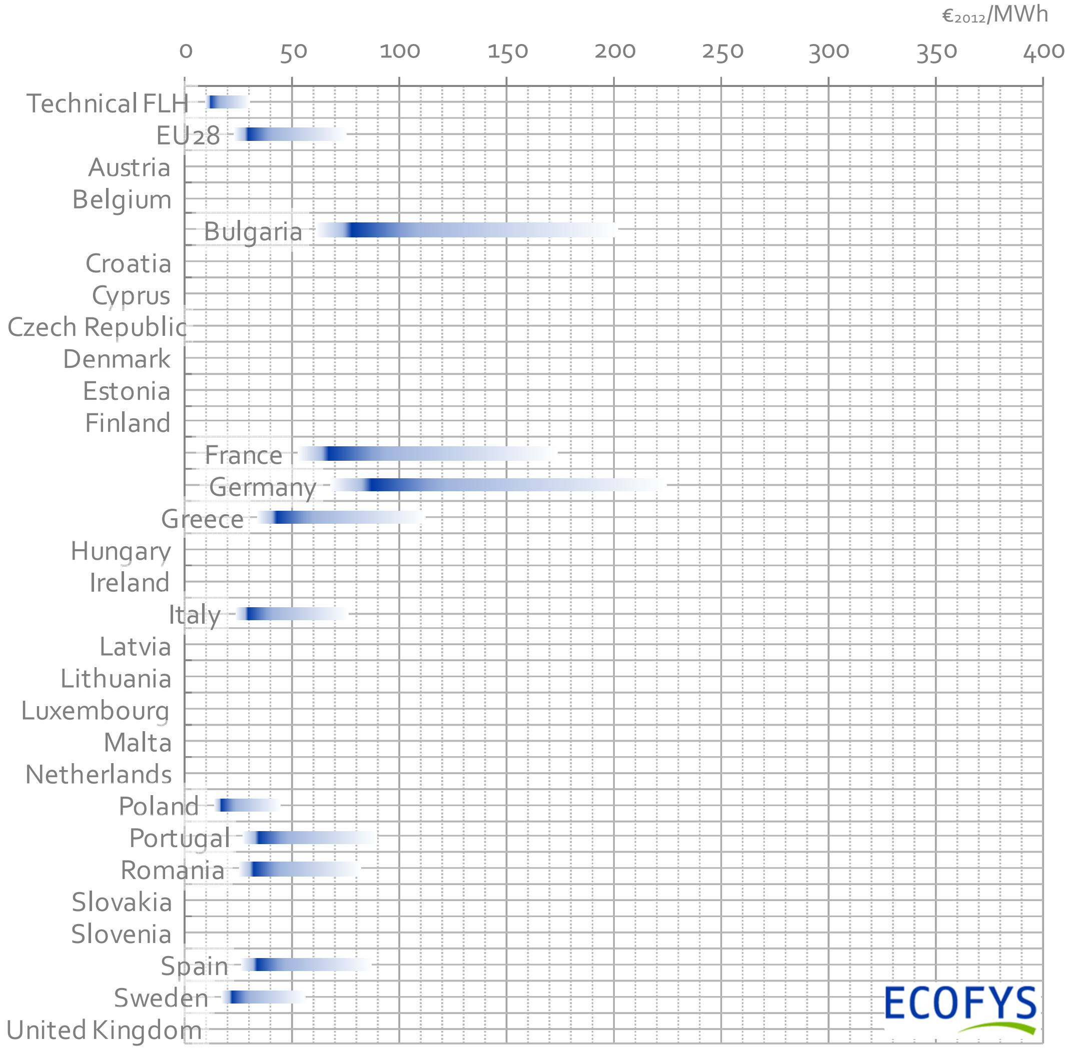

Figure A4-4: Levelised cost of electricity in the EU28 Member States for large scale hydropower. Member States to which the technology is not applicable or for which insufficient data is available are indicated on the left side of the chart.

Cost differences are primarily caused by differences in full load hours. Note that small scale hydropower, including smaller reservoirs, is included in the category run-of-river (e.g. in Belgium and UK). The full load hours reported for hydropower have a large uncertainty because there is no consistent public dataset that consistently reports both installed capacity and production. Consequently, this introduces an uncertainty in the presented LCOEs.
Although hydropower production in Denmark, Estonia, Luxembourg, Croatia and Slovenia is reported, no consistent data were available on these countries.

A4.3.4 Nuclear (new plants)

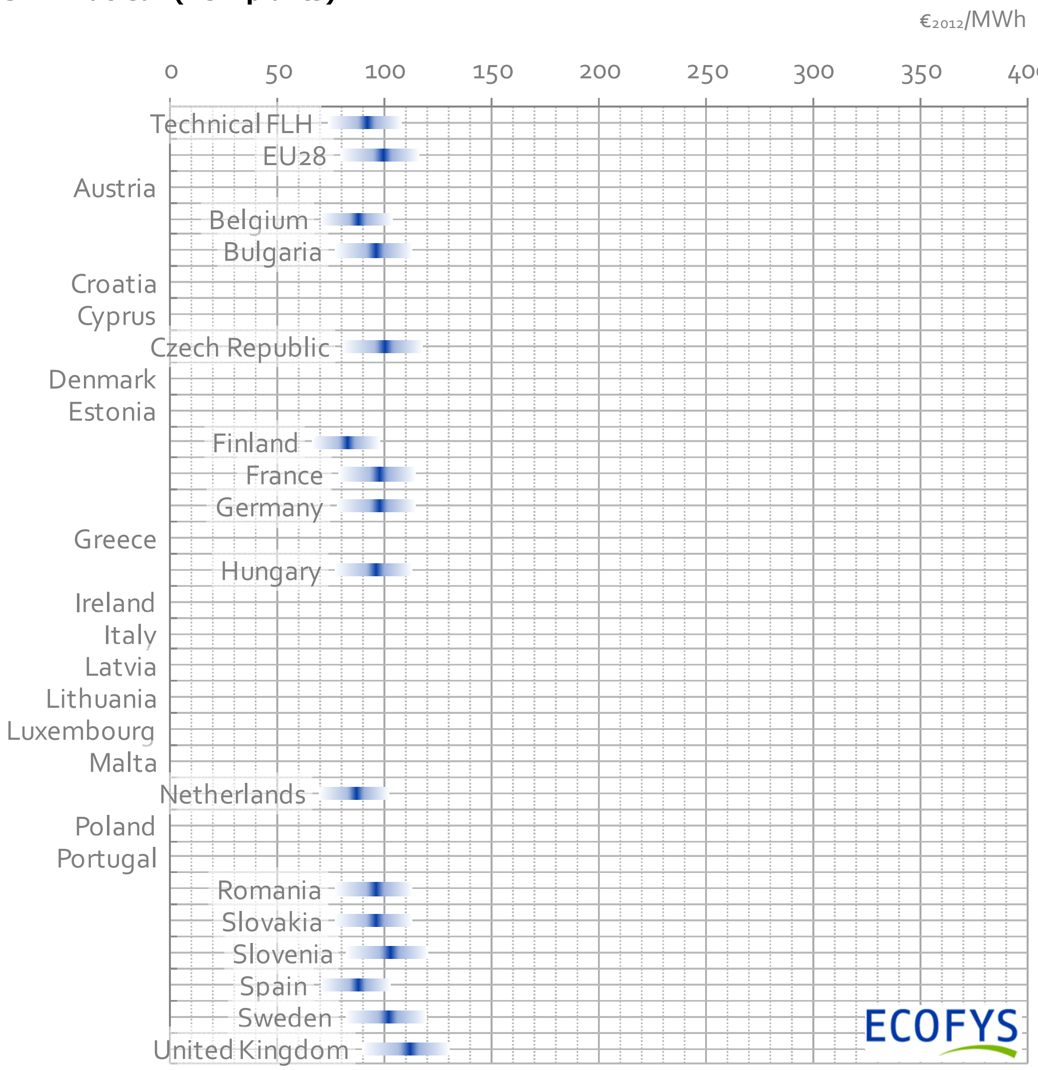

Figure A4-5: Levelised cost of electricity in the EU28 Member States for nuclear power. Member States to which the technology is not applicable are indicated on the left side of the chart.

Nuclear power generation costs do not vary significantly across Europe. As this technology serves as a base load technology and is independent of local resources the full load hours do not vary significantly over Member States.

A4.3.5 Solar PV – rooftop

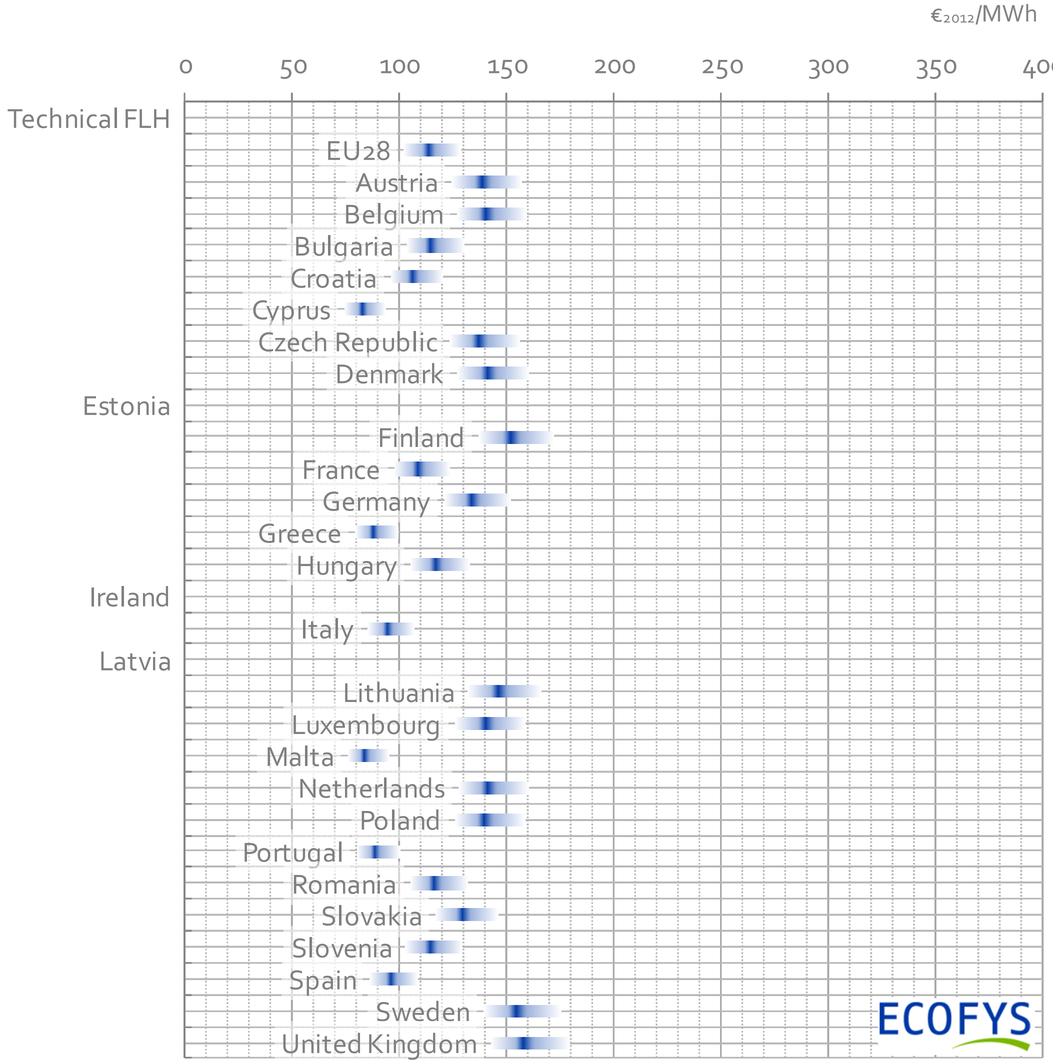

Figure A4-6: Levelised cost of electricity in the EU28 Member States for small scale solar PV, installed in 2012. Member States to which the technology is not applicable are indicated on the left side of the chart. 'Technical FLH' is not shown because the LCOE is already based on resource availability in individual Member States.

For solar PV we present costs for both 2008 and 2012, because the costs have decreased rapidly in recent years. The costs apply to solar PV installed in the given years. The differences between Member States are caused by differences in irradiation and thus annual production.
Levelised costs of small scale PV have been calculated with a lower discount rate (4%). If higher discount rates (equal to those applied to large scale PV: 5-7%) are used, levelised costs will be 15-20% higher.

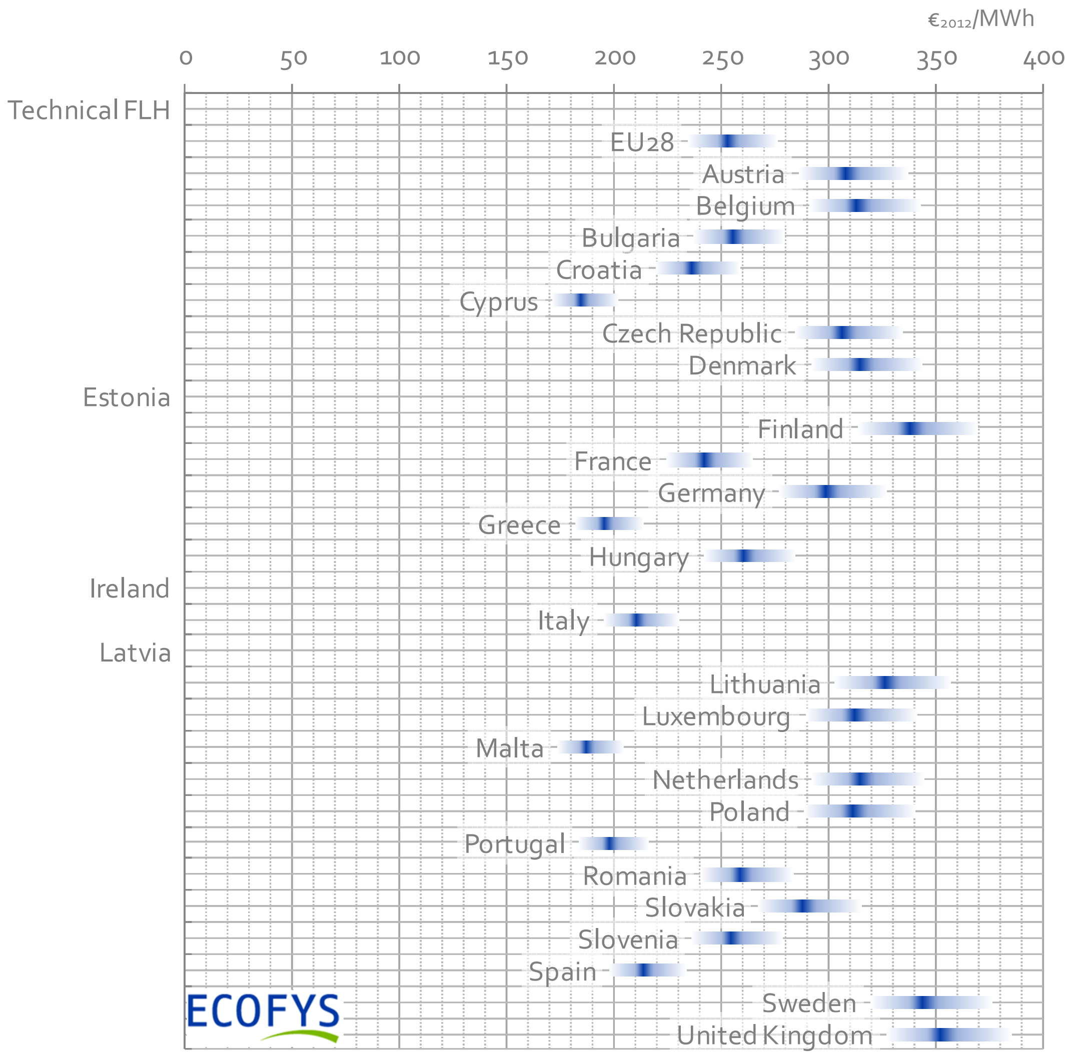

Figure A4-7: Levelised cost of electricity in the EU28 Member States for small scale solar PV, installed in 2008. Member States to which the technology is not applicable are indicated on the left side of the chart. 'Technical FLH' is not shown because the LCOE is already based on resource availability in individual Member States.

A4.3.6 Solar PV – ground-mounted

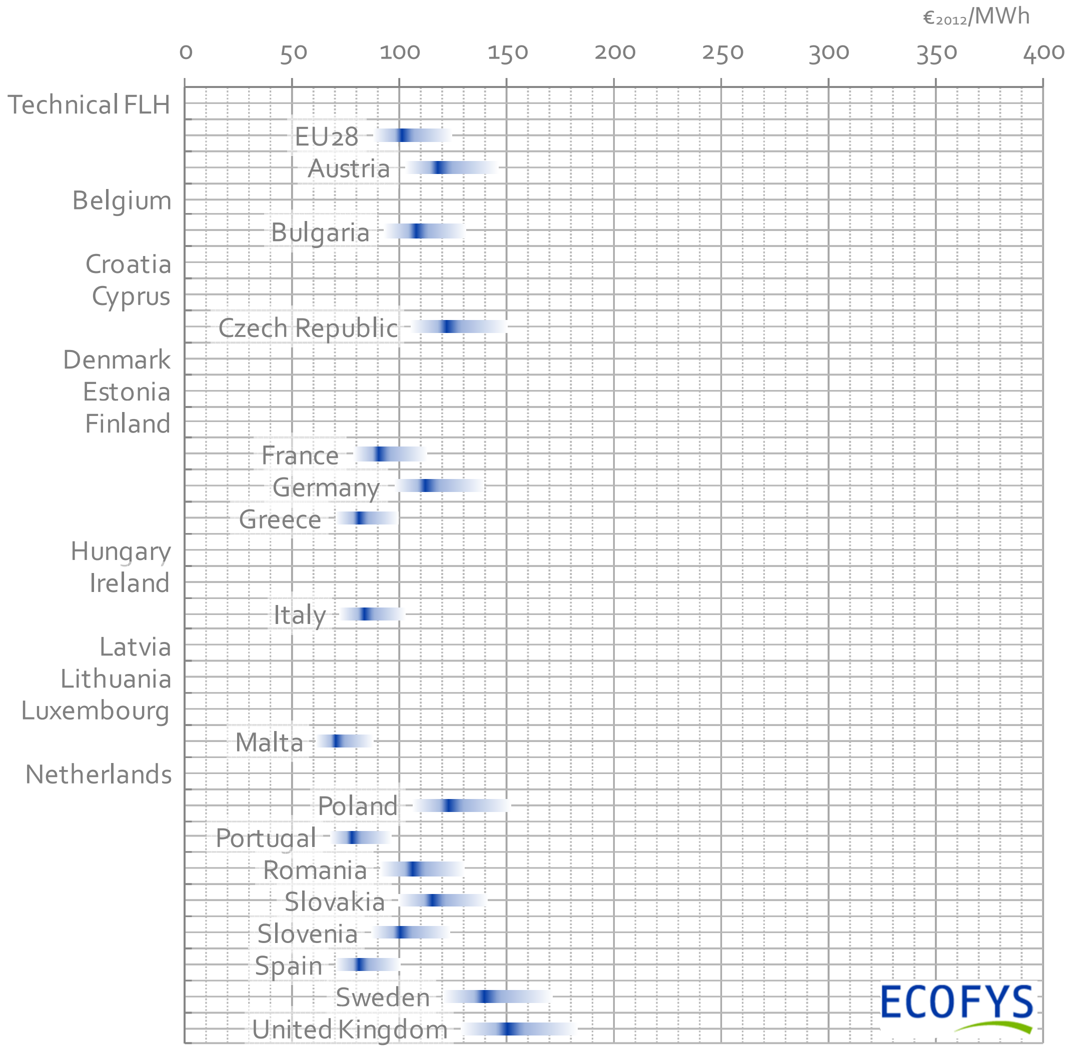

Figure A4-8: Levelised cost of electricity in the EU28 Member States for large scale solar PV, installed in 2012. Member States to which the technology is not applicable are indicated on the left side of the chart. 'Technical FLH' is not shown because the LCOE is already based on resource availability in individual Member States.

For solar PV we present costs for both 2008 and 2012, because the costs have decreased rapidly in recent years. The costs apply to solar PV installed in the given years. The differences between Member States are caused by differences in irradiation and thus annual production. Costs are slightly lower compared to small scale PV, this can be attributed to lower investments costs.

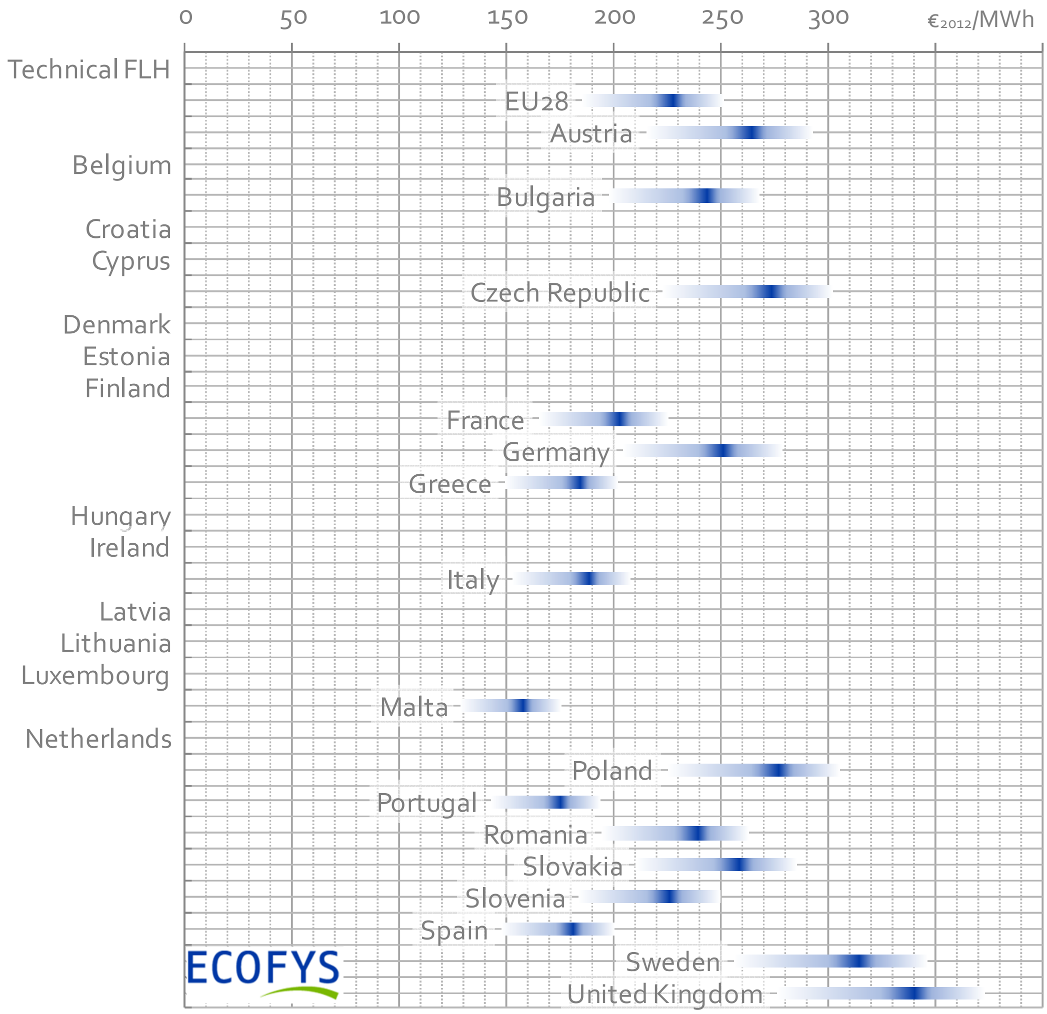

Figure A4-9: Levelised cost of electricity in the EU28 Member States for large scale solar PV, installed in 2008. Member States to which the technology is not applicable are indicated on the left side of the chart. 'Technical FLH' is not shown because the LCOE is already based on resource availability in individual Member States.

A4.3.7 Wind onshore

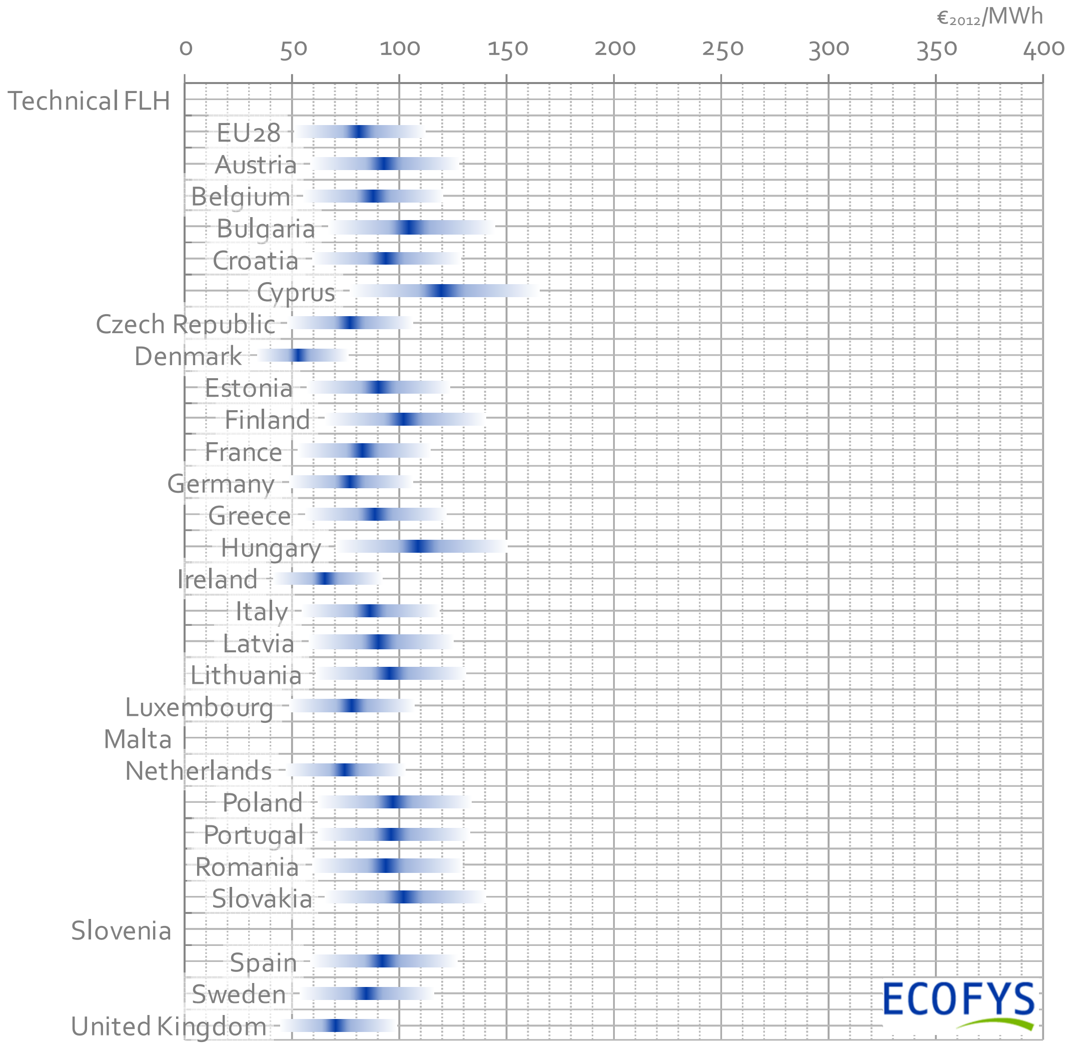

Figure A4-10: Levelised cost of electricity in the EU28 Member States for onshore wind power. Member States to which the technology is not applicable are indicated on the left side of the chart. 'Technical FLH' is not shown because the LCOE is already based on resource availability in individual Member States.

The differences between Member States are caused by differences in average wind speeds and annual wind yields and thus annual production.

A4.3.8 Wind offshore

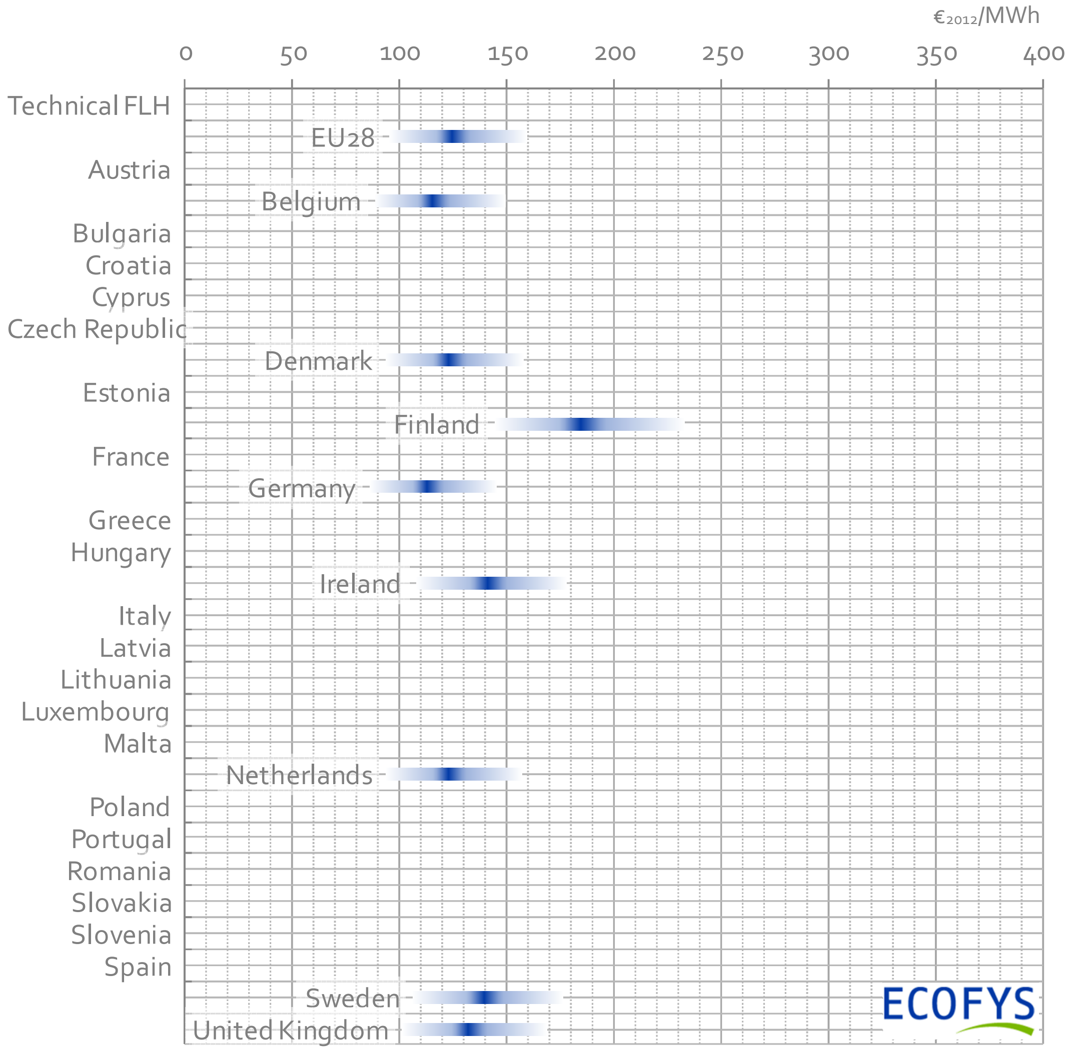

Figure A4-11: Levelised cost of electricity in the EU28 Member States offshore wind power, excluding investments in offshore connections. Member States to which the technology is not applicable are indicated on the left side of the chart. 'Technical FLH' is not shown because the LCOE is already based on resource availability in individual Member States.

Wind offshore requires an offshore grid-connection. Because system costs for other technologies are excluded in the LCOE calculations, the figure above excludes the investments costs for offshore transport and distribution cost (e.g. cabling). However, since investments in cabling are significant, we present the impact on the levelised costs in the figure below. By taking into account grid connections costs, levelised costs increase by approximately 25%. These costs might decrease once more offshore wind farms are commissioned and more farms can be connected to existing offshore connections.

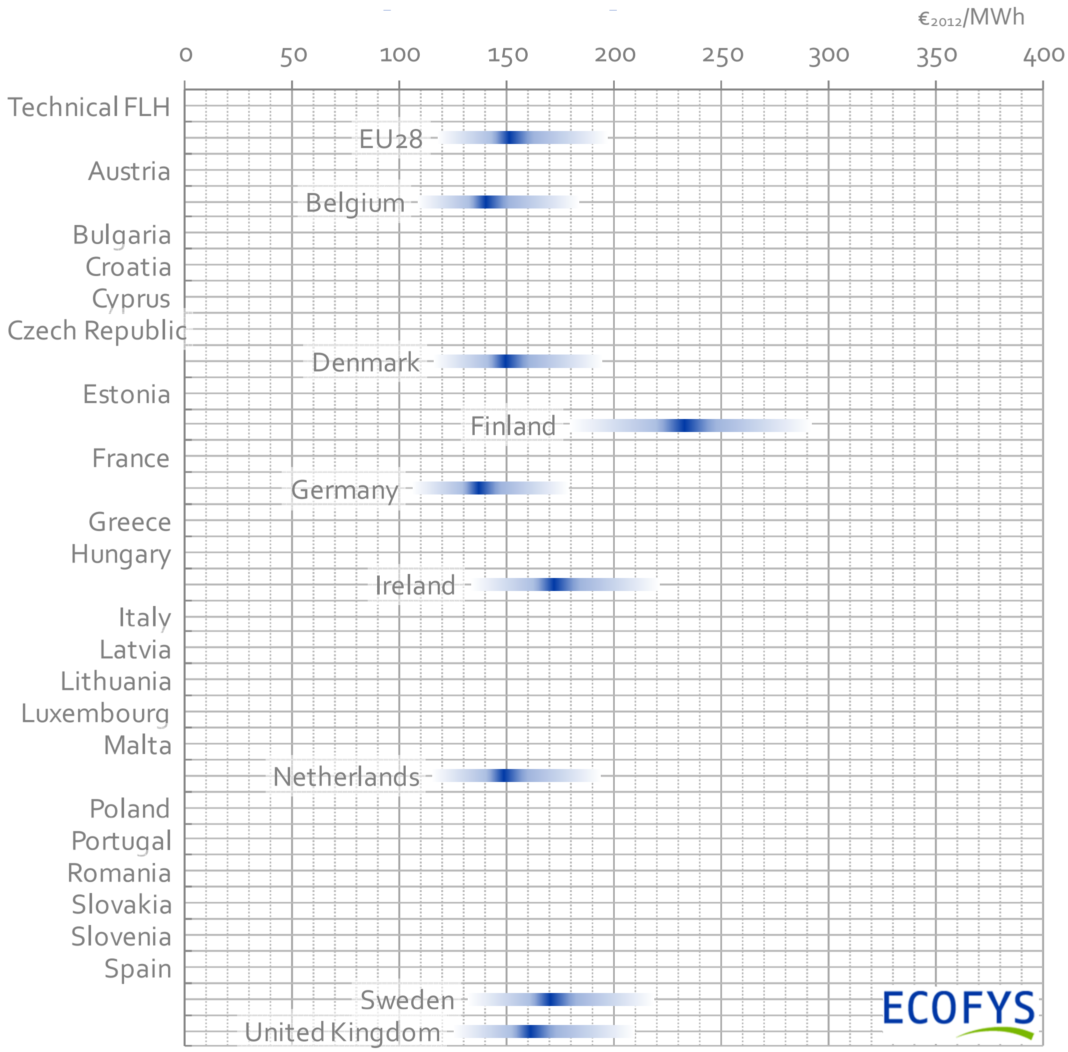

Figure A4-12: Levelised cost of electricity in the EU28 Member States offshore wind power, including investments in offshore connections. Member States to which the technology is not applicable are indicated on the left side of the chart. 'Technical FLH' is not shown because the LCOE is already based on resource availability in individual Member States.

A4.3.9 Geothermal electricity

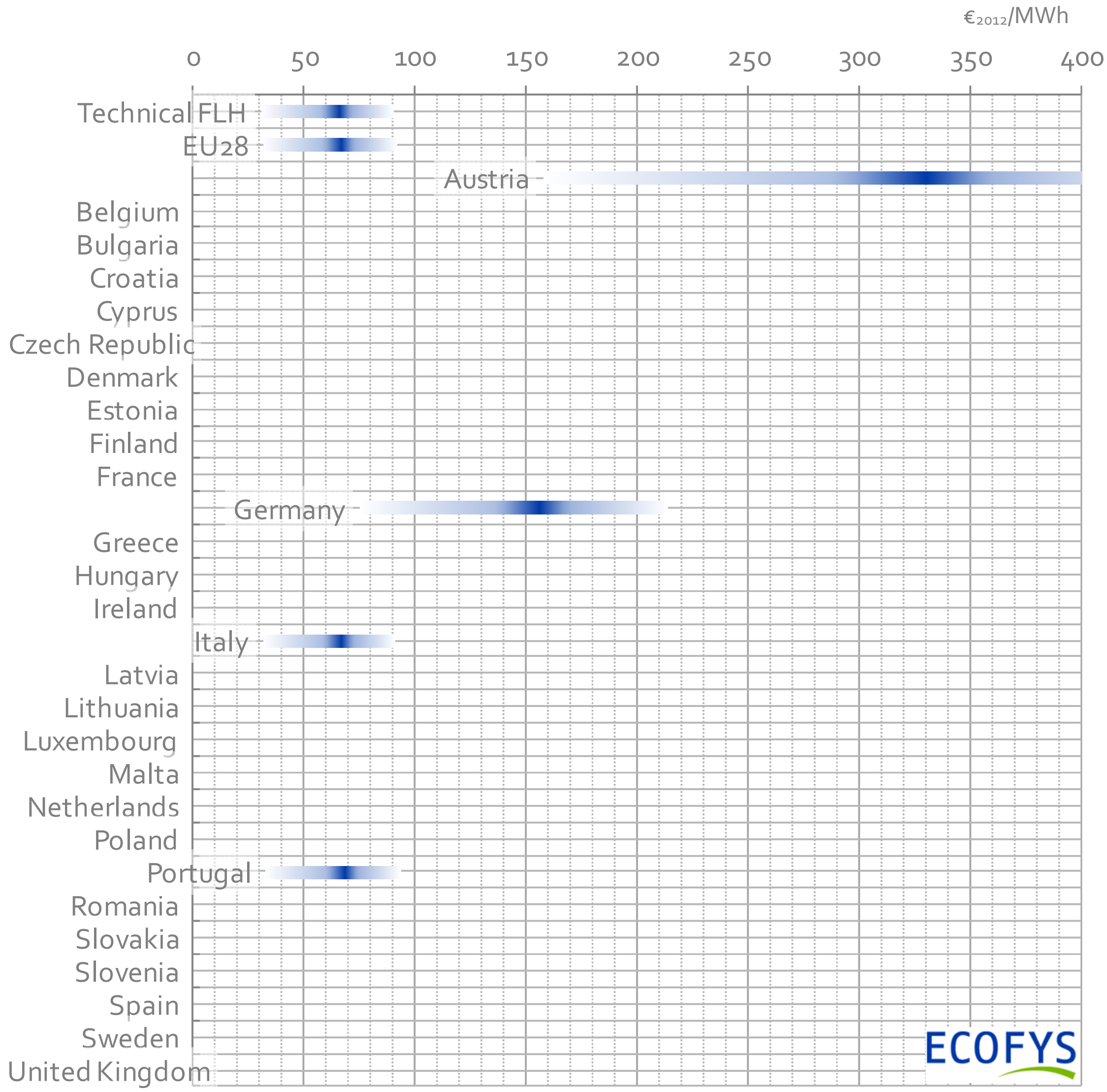

Figure A4-13: Levelised cost of electricity in the EU28 Member States for geothermal power. Member States to which the technology is not applicable are indicated on the left side of the chart.

Geothermal power in Europe is mainly generated in Italy. The other three countries have little installed capacity, especially Austria, which has only 1 MW installed. Investment costs are based on dedicated power generation (i.e. not CHP), while some units might also serve as heat producers. Furthermore, investments costs reflect costs for high temperature geothermal power generation; costs for low temperature geothermal power generation could be higher. In Italy and Portugal, plants are operated nearly full time, yielding low levelised costs. In Austria installations run fewer hours, which results in higher costs.

A4.3.10 Oil

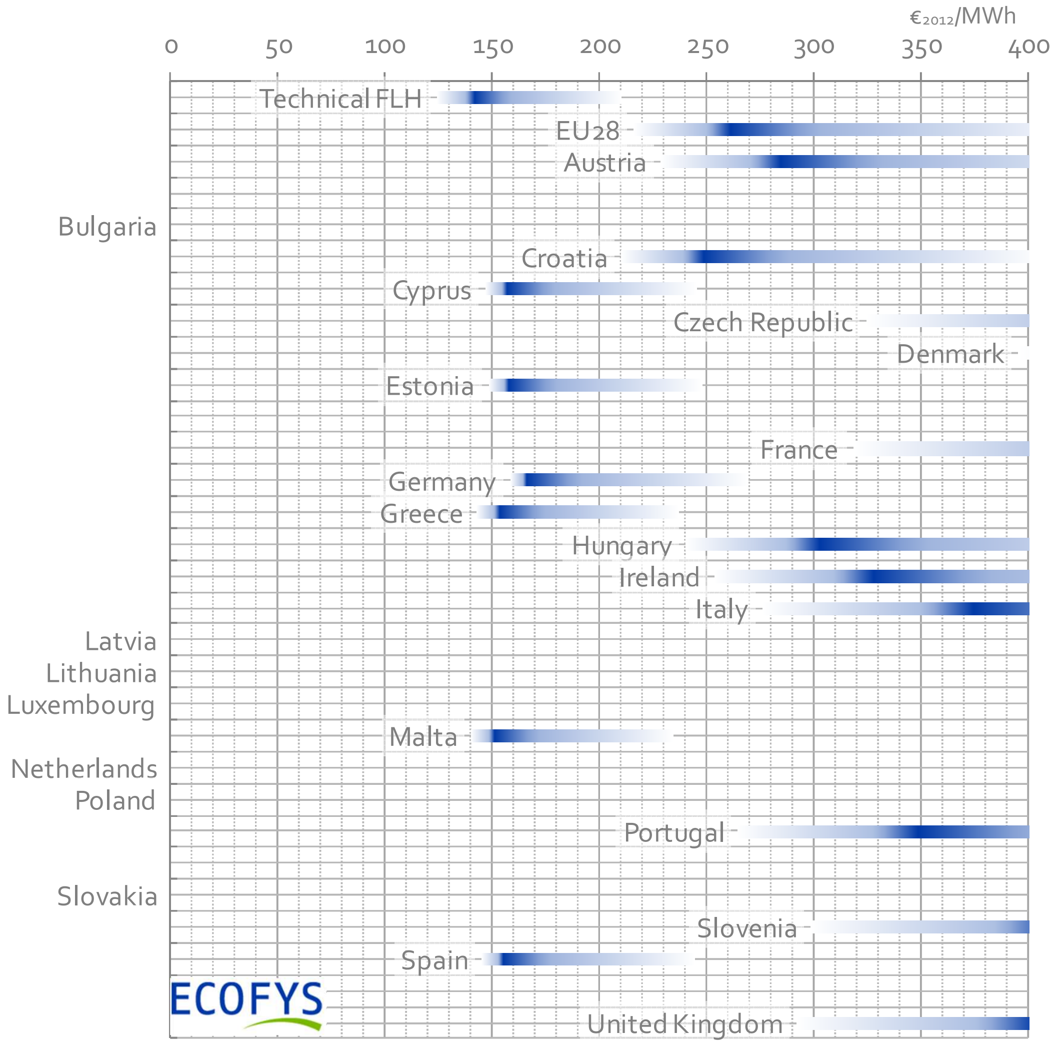

Figure A4-14: Levelised cost of electricity in the EU28 Member States for oil power. Member States to which the technology is not applicable are indicated on the left side of the chart.

Oil fired power plants are mainly used to meet peak loads and as back-up capacities: relatively expensive oil pushes this technology to the end of the merit-order. As such, the relatively low amount of FLH increases the levelised cost of oil-fired power production.

Notable exceptions are islands grids: Malta, Spain (mainly based on its islands), Estonia (tar sands), Greece and Cyprus.

A4.3.11 Coal

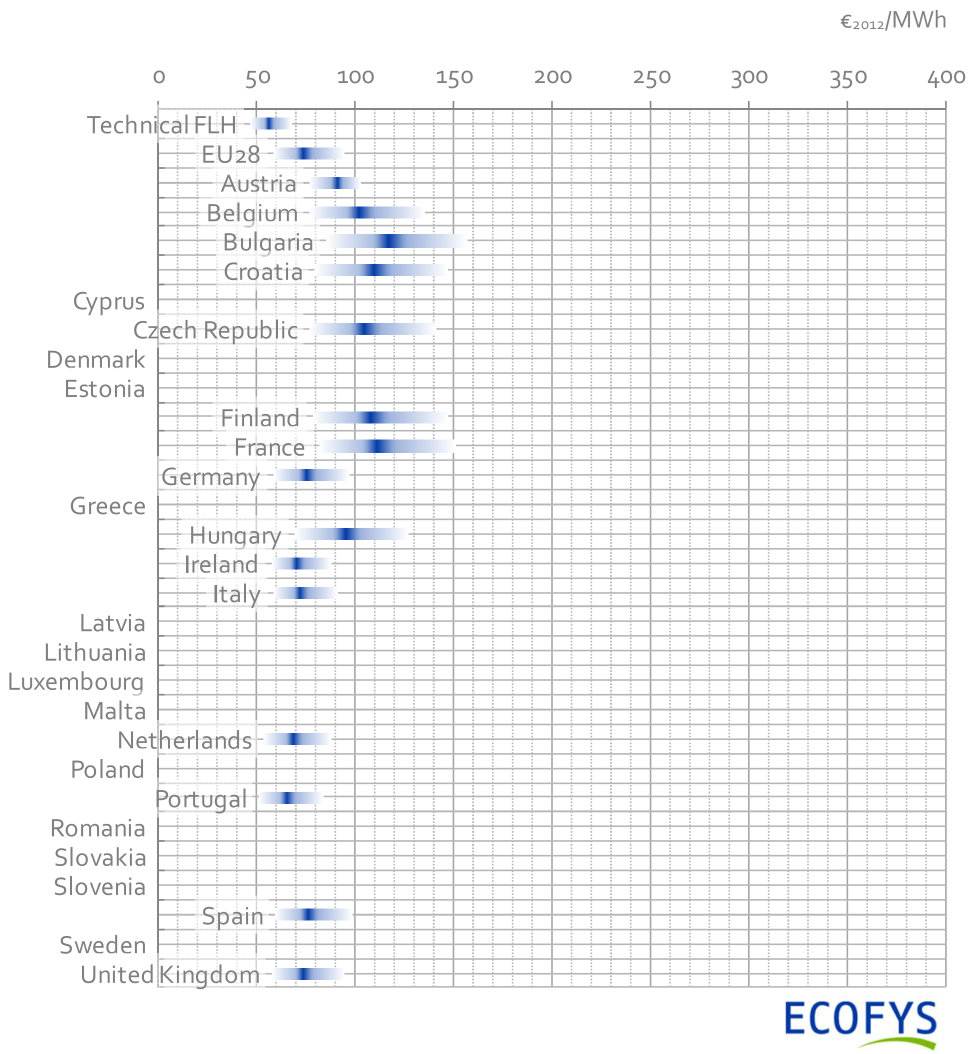

Figure A4-15: Levelised cost of electricity in the EU28 Member States for coal power. Member States to which the technology is not applicable are indicated on the left side of the chart.

In many MS coal is used as a base-load technology. Exceptions are Finland, Bulgaria and France, where nuclear and/or hydropower displaces coal in the merit order. In Bulgaria, lignite coal power is also dominant in the energy mix, at the expense of hard coal.

These costs exclude Poland, as Eurostat statistics report all Polish coal-fired power generation as originating from coal-fired CHP plants. Therefore, no FLH and thus levelised cost for Polish plants can be derived.

A4.3.12 Natural gas

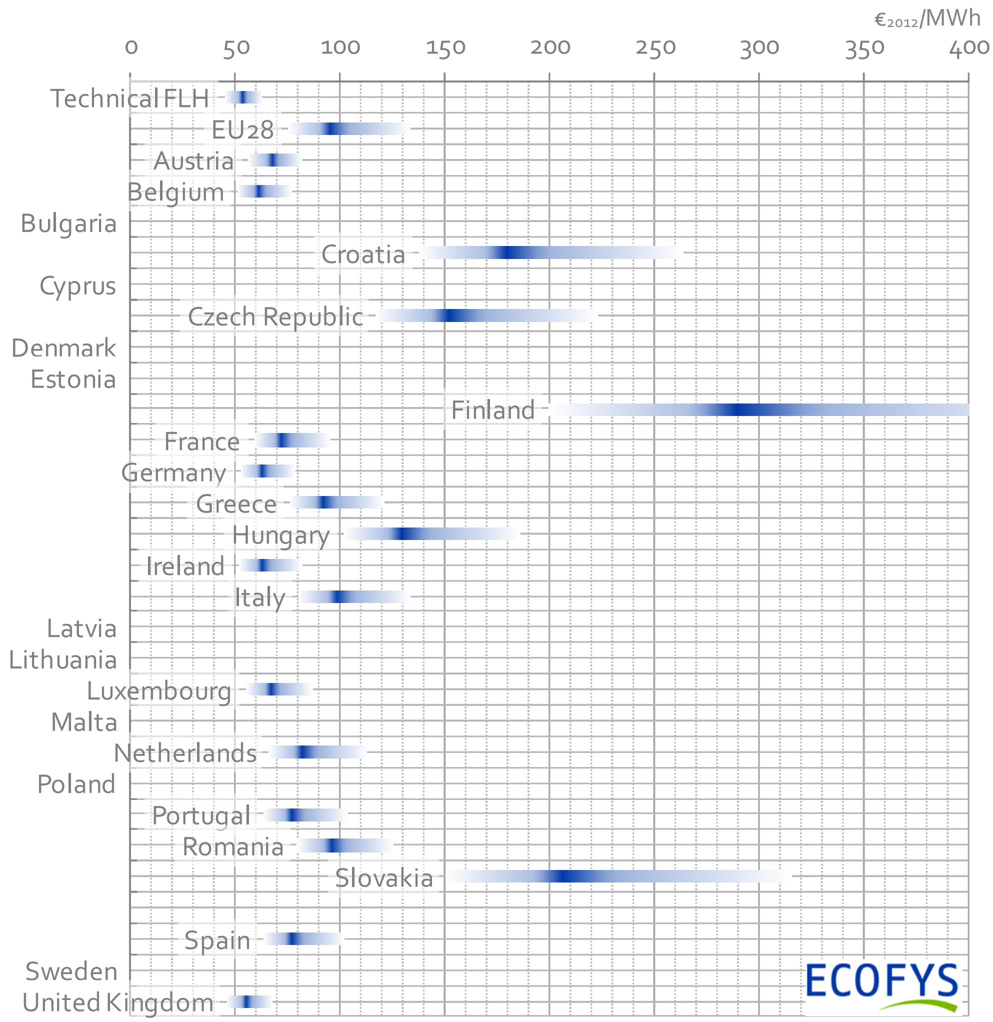

Figure A4-16: Levelised cost of electricity in the EU28 Member States for natural gas power (CCGT). Member States to which the technology is not applicable are indicated on the left side of the chart.

The high result for Finland reflects a very limited amount of gas capacity, i.e. it only used around 200 equivalent FLHs, increasing the levelised costs.

A4.3.13 Biomass dedicated

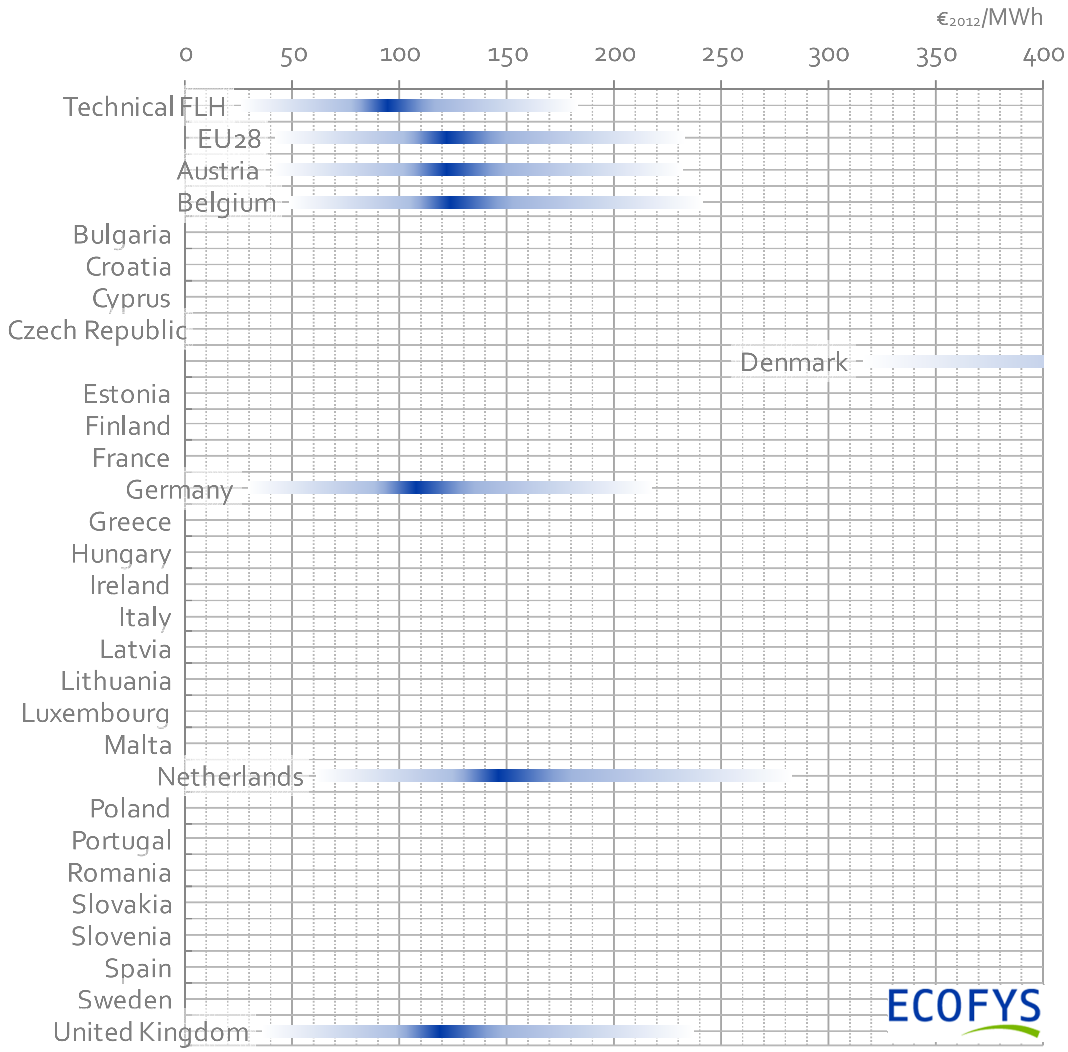

Figure A4-17: Levelised cost of electricity in the EU28 Member States for dedicated biomass. Member States to which the technology is not applicable are indicated on the left side of the chart.

The above graph show the cost of biomass power fuelled with waste (free) and biomass pellets (relatively high price). Other biomass (waste) streams are used as well, for example wood chips, but the costs of these streams vary hugely and no consistent market data exists, therefore, only costs are shown for Member States where a pellet market exists. The range in levelised costs is caused by a range investments costs as well as fuel prices (ranging from free waste to pellets). The high levelised costs in Denmark are caused by a small amount of FLHs.

A4.3.14 CHP gas – heat

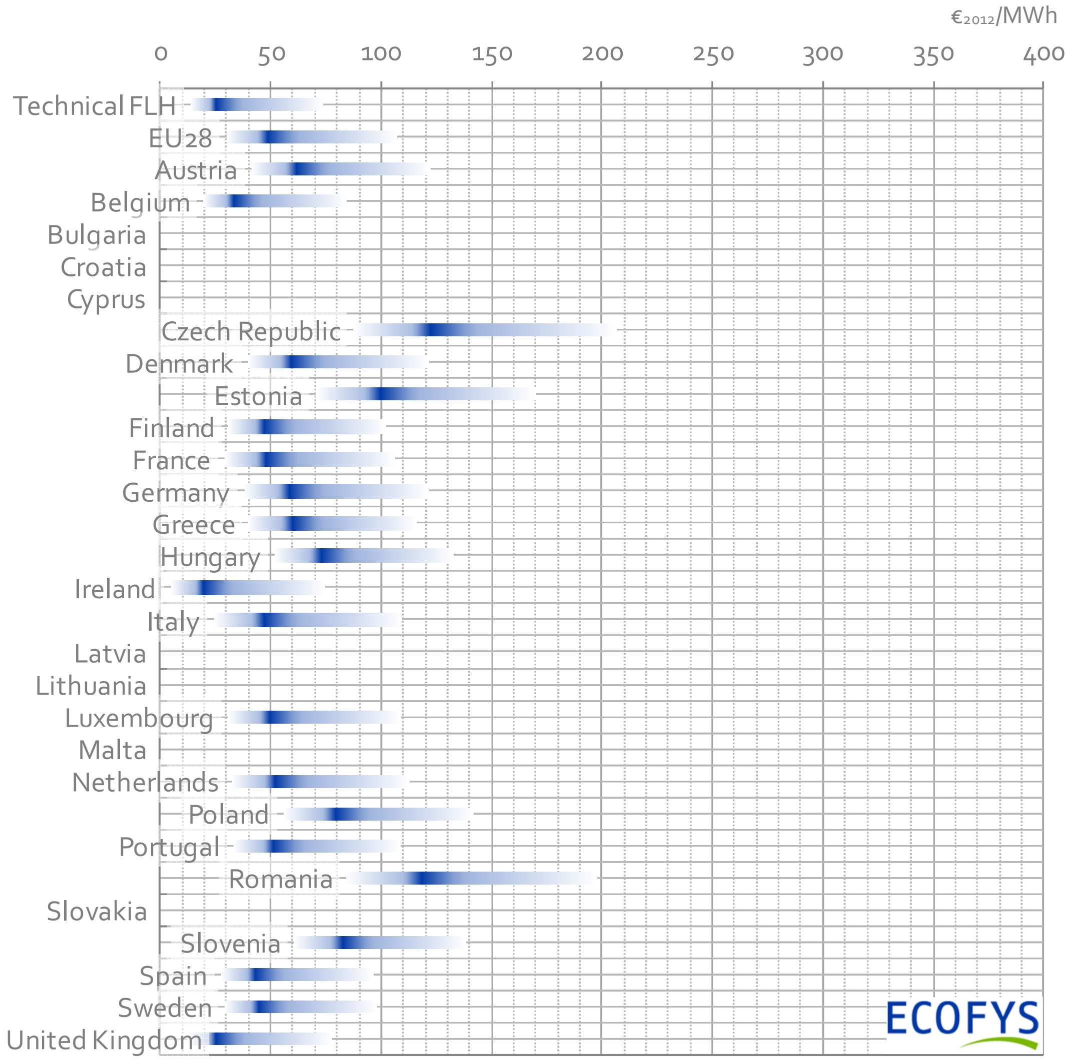

Figure A4-18: Levelised cost of heat in the EU28 Member States for CHP gas, with electricity production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

To calculate the levelised cost of CHP, Eurostat statistics were used. Since CHP is applied in a range of sectors and processes, FLHs and the options to sell electricity vary from installation to installation. The range indicated here only reflects a range in investment costs and not in FLHs. This means that the range of levelised costs could be higher than shown in the graph below.

A4.3.15 CHP gas – electricity

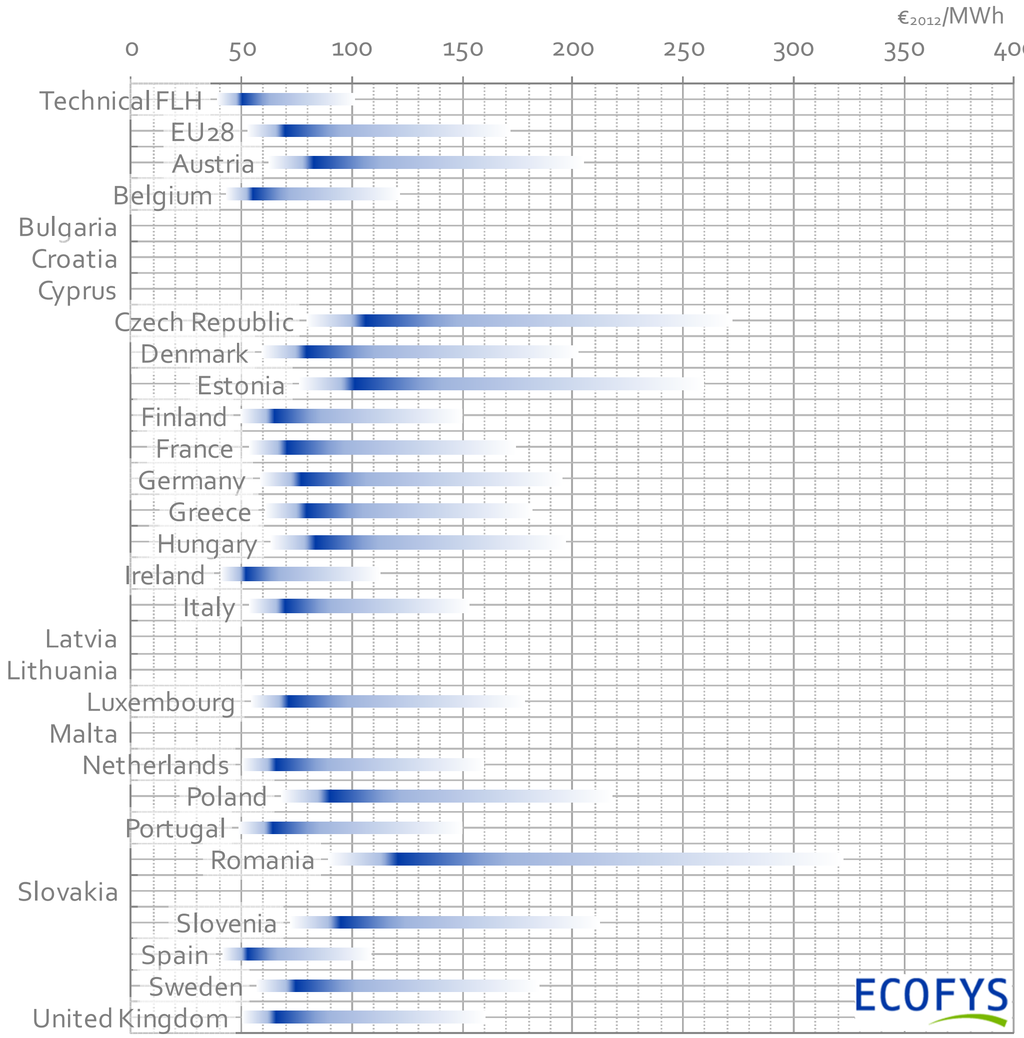

Figure A4-19: Levelised cost of electricity in the EU28 Member States for CHP gas, with heat production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

To calculate the levelised cost of CHP, Eurostat statistics were used. Since CHP is applied in a range of sectors and processes, FLHs and the options to sell electricity vary from installation to installation. The range indicated here only reflects a range in investment costs and not in FLHs. This means that the range of levelised costs could be larger that shown in the graph below.

In the calculations to calculate the levelised cost of electricity from CHP it is assumed that all heat can be utilised or sold. This is not the case for all installations and this could increase the LCOE from CHP.

A4.3.16 CHP coal – heat

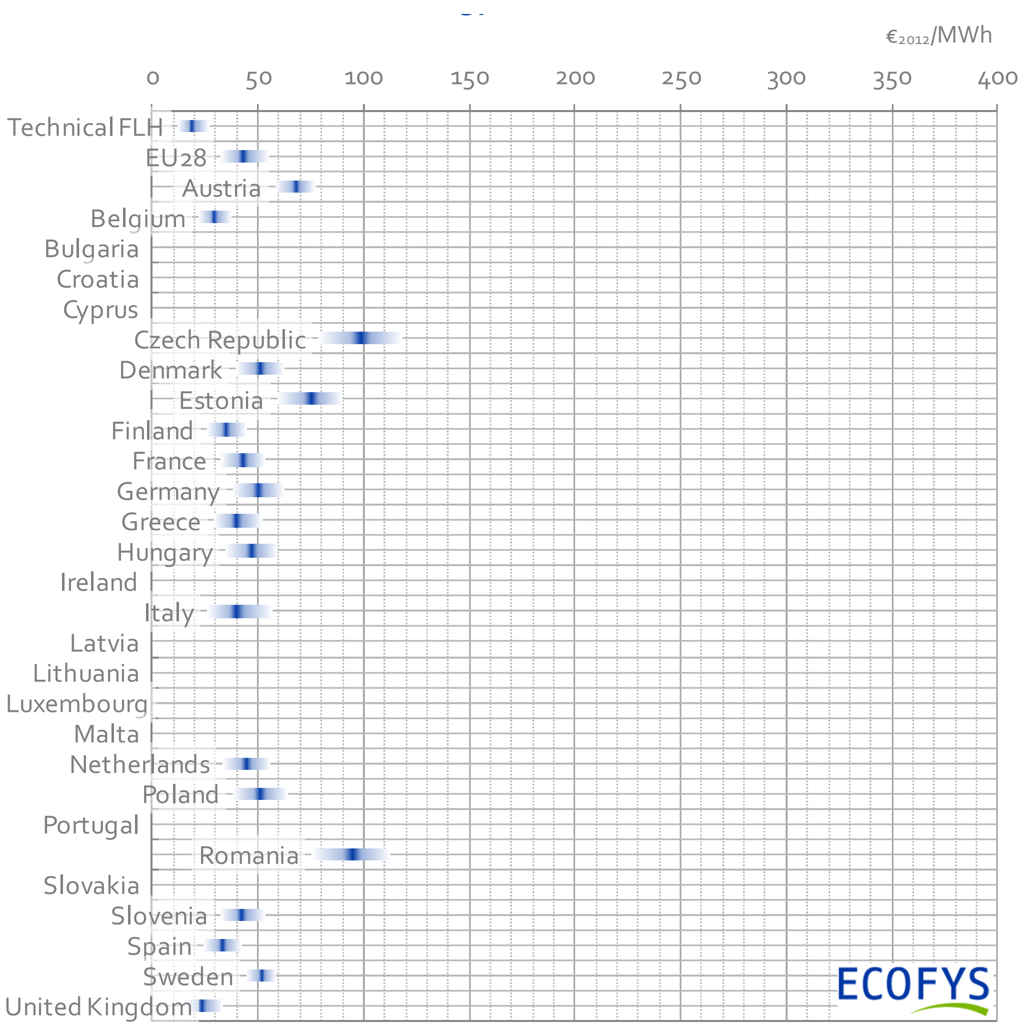

Figure A4-20: Levelised cost of heat in the EU28 Member States for CHP coal, with electricity production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

See the section on CHP gas for some general remarks on CHP.

Relatively high levelised costs in Romania and Czech Republic are caused by a lower FLH.

A4.3.17 CHP coal – electricity

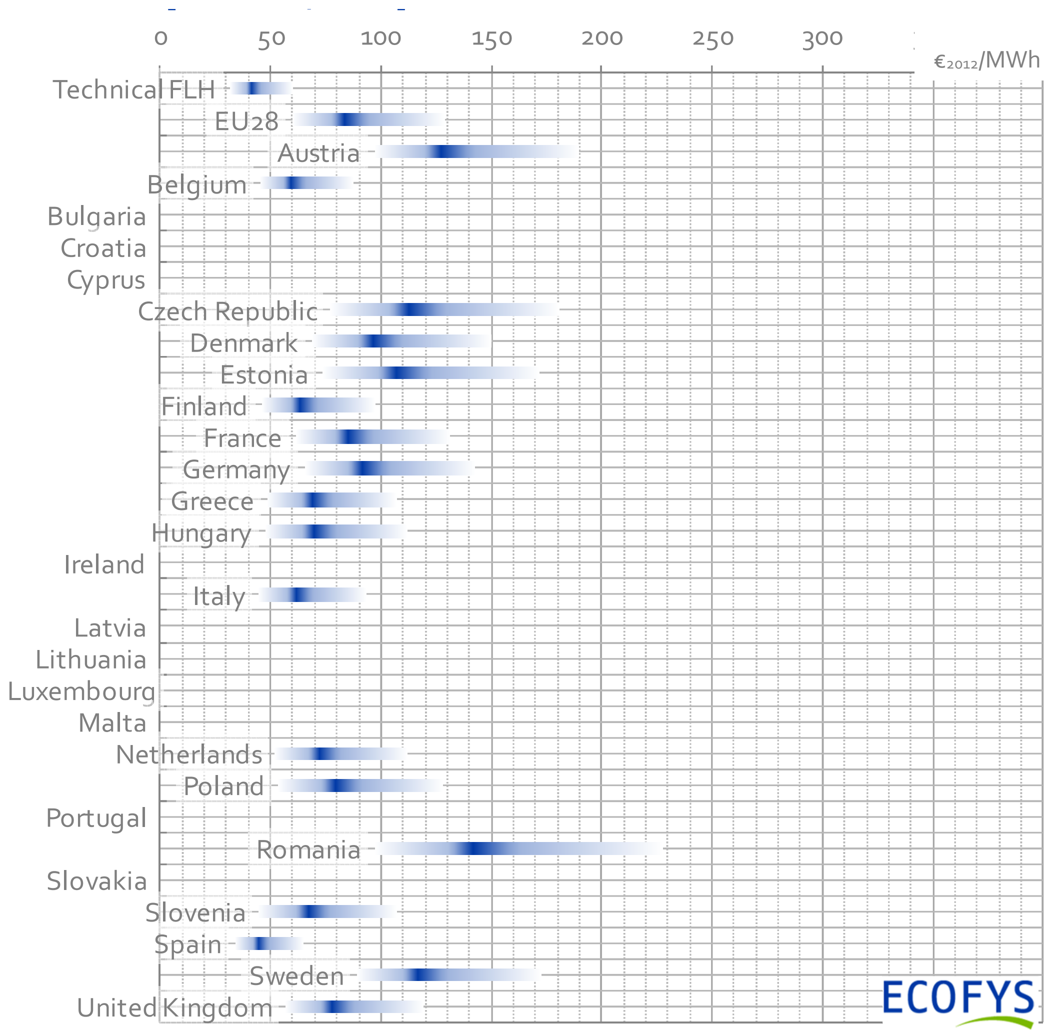

Figure A4-21: Levelised cost of electricity in the EU28 Member States for CHP coal, with heat production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

See the section on CHP gas for some general remarks on CHP.

A4.3.18 CHP waste – heat

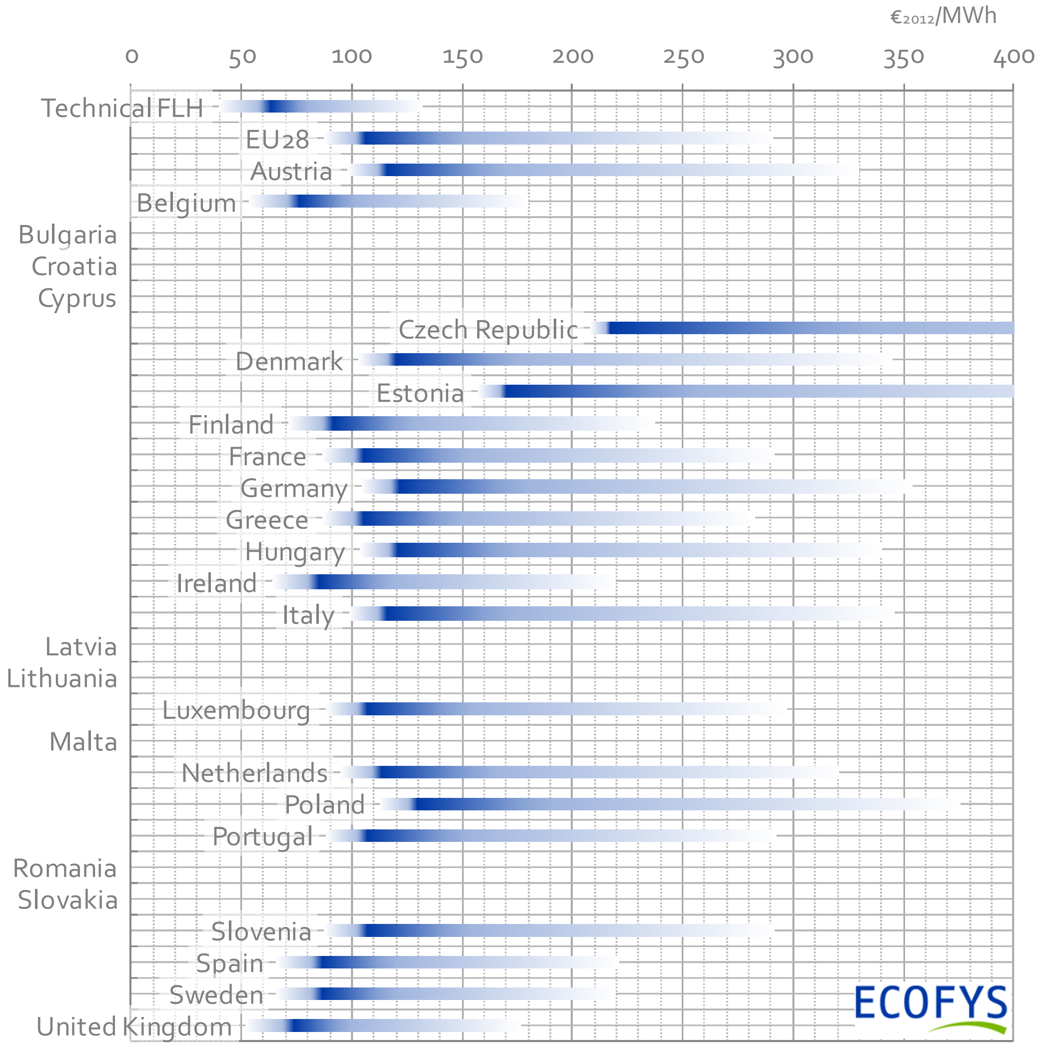

Figure A4-22: Levelised cost of heat in the EU28 Member States for CHP waste, with electricity production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

See the section on CHP gas for some general remarks on CHP. Higher costs for CHP waste are mainly caused by high investment costs. The wide ranges are also caused by a wide range of reported costs of these installations. However, it can be argued that the investment costs should be allocated to waste processing activities and not to energy conversion. On the other hand, costs of waste might be positive (i.e. waste has a prices on some locations) which could further increase levelised costs.

A4.3.19 CHP waste – electricity

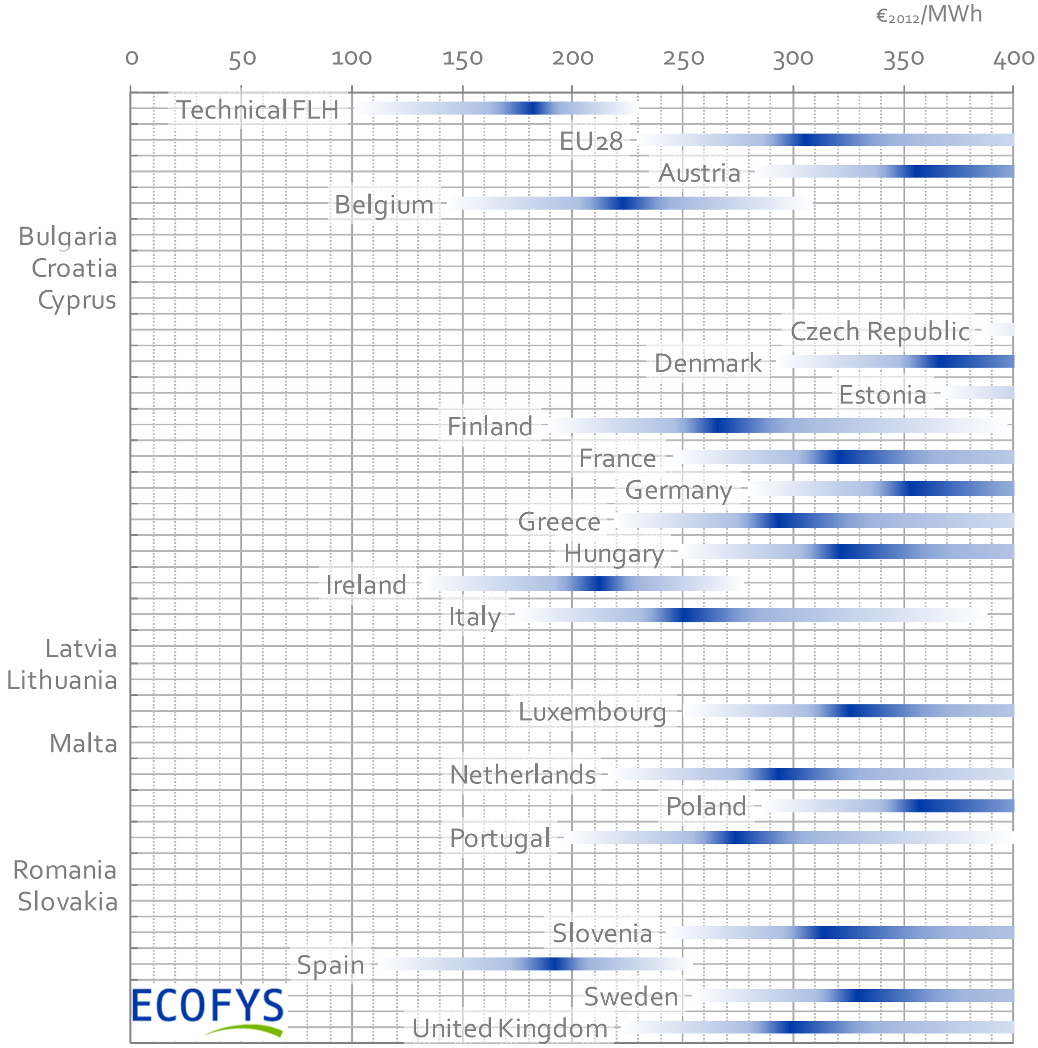

Figure A4-23: Levelised cost of electricity in the EU28 Member States for CHP waste, with heat production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

See the section on CHP gas for some general remarks on CHP.

Because the fuel price of waste is assumed to be zero, the costs differences are mainly caused by differences in FLH (the differences in WACC have a limited effect).

A4.3.20 CHP biomass – heat

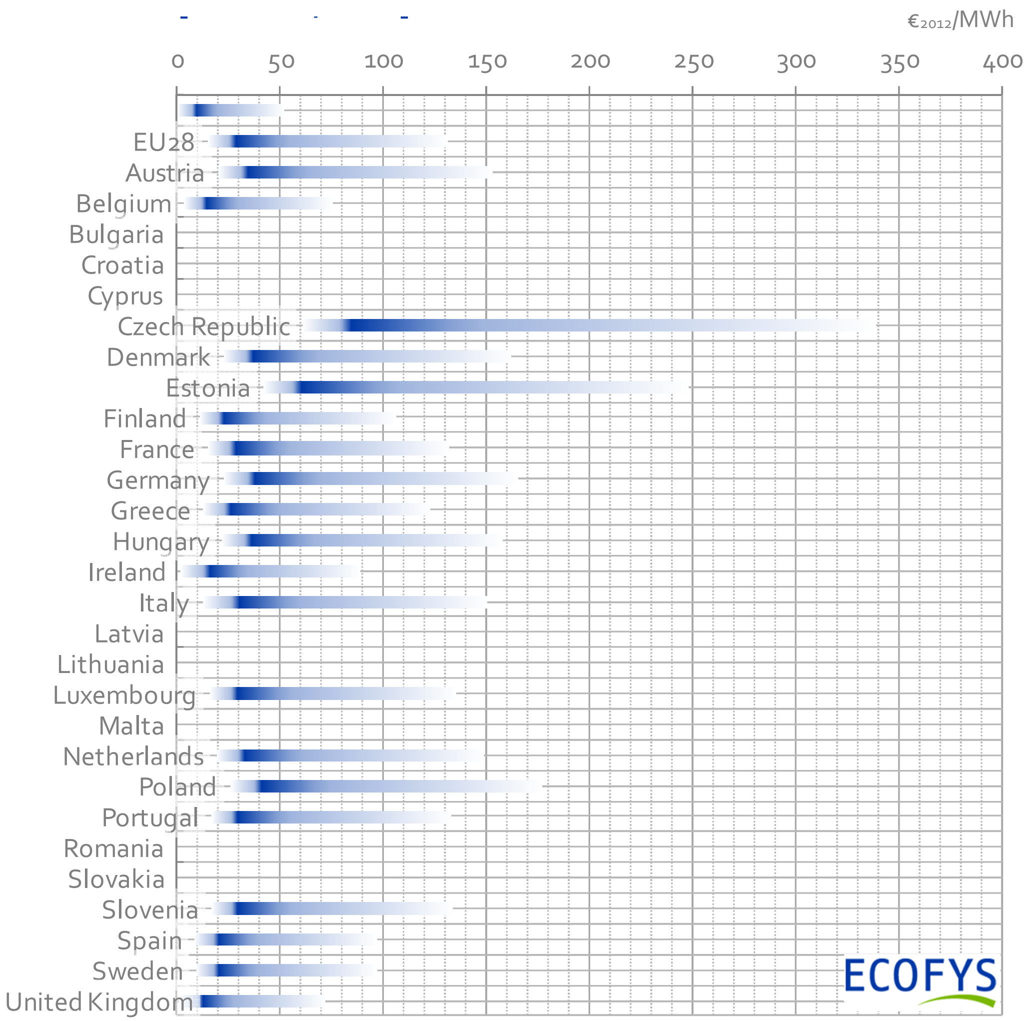

Figure A4-24: Levelised cost of heat in the EU28 Member States for CHP biomass, with electricity production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

See the section on CHP gas for some general remarks on CHP. The levelised costs presented here correspond to costs for conversion of biomass waste streams (for example in waste incineration). However, if no waste streams are available, biomass has a price and levelised costs will increase.

Similar to waste, the fuel price of biomass is also assumed to be zero, so the costs differences are mainly caused by differences in FLHs.

A4.3.21 CHP biomass – electricity

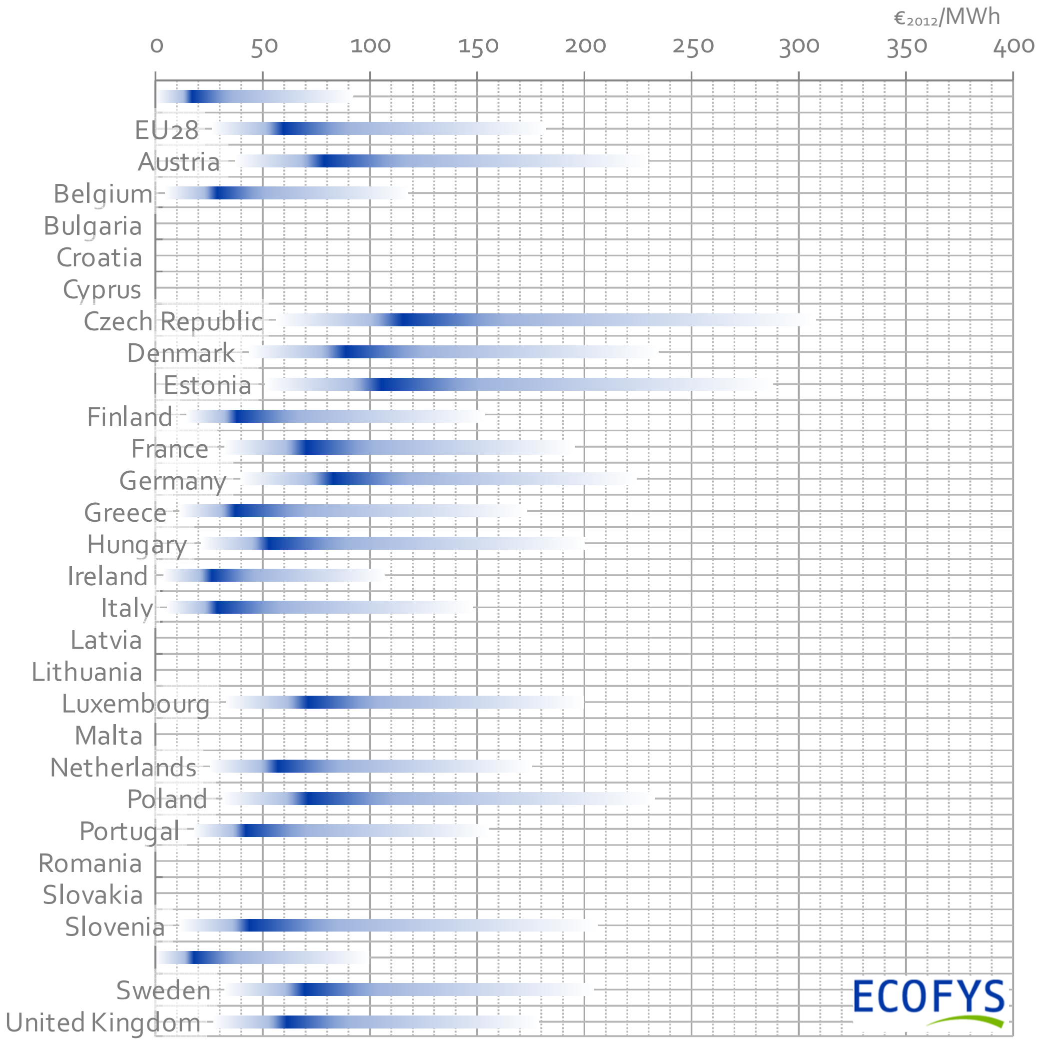

Figure A4-25: Levelised cost of electricity in the EU28 Member States for CHP biomass, with heat production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

See the section on CHP gas for some general remarks on CHP. If pellets are used in the CHP plants, cost would increase by approximately €35-45/MWh.

A4.3.22 CHP Industry gas - heat

The cost of industrial CHP is only presented as levelised cost of heat because the assumed number of full load hours (8000) is based on heat demand required for industrial processes and not electricity demand.

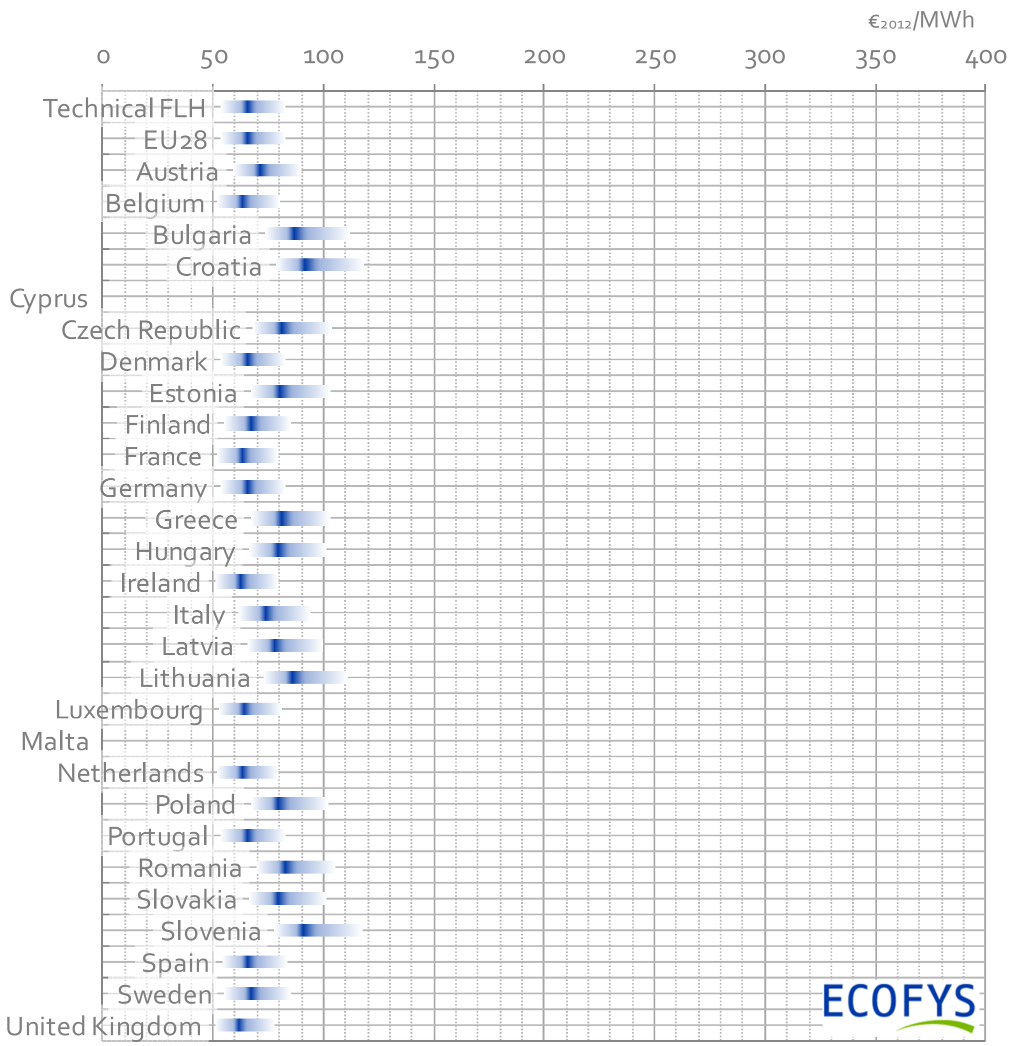

Figure A4-26: Levelised cost of heat in the EU28 Member States for industrial CHP (gas), with electricity production as revenue. Member States to which the technology is not applicable are indicated on the left side of the chart.

A4.3.23 Domestic gas-fired boilers (condensing)

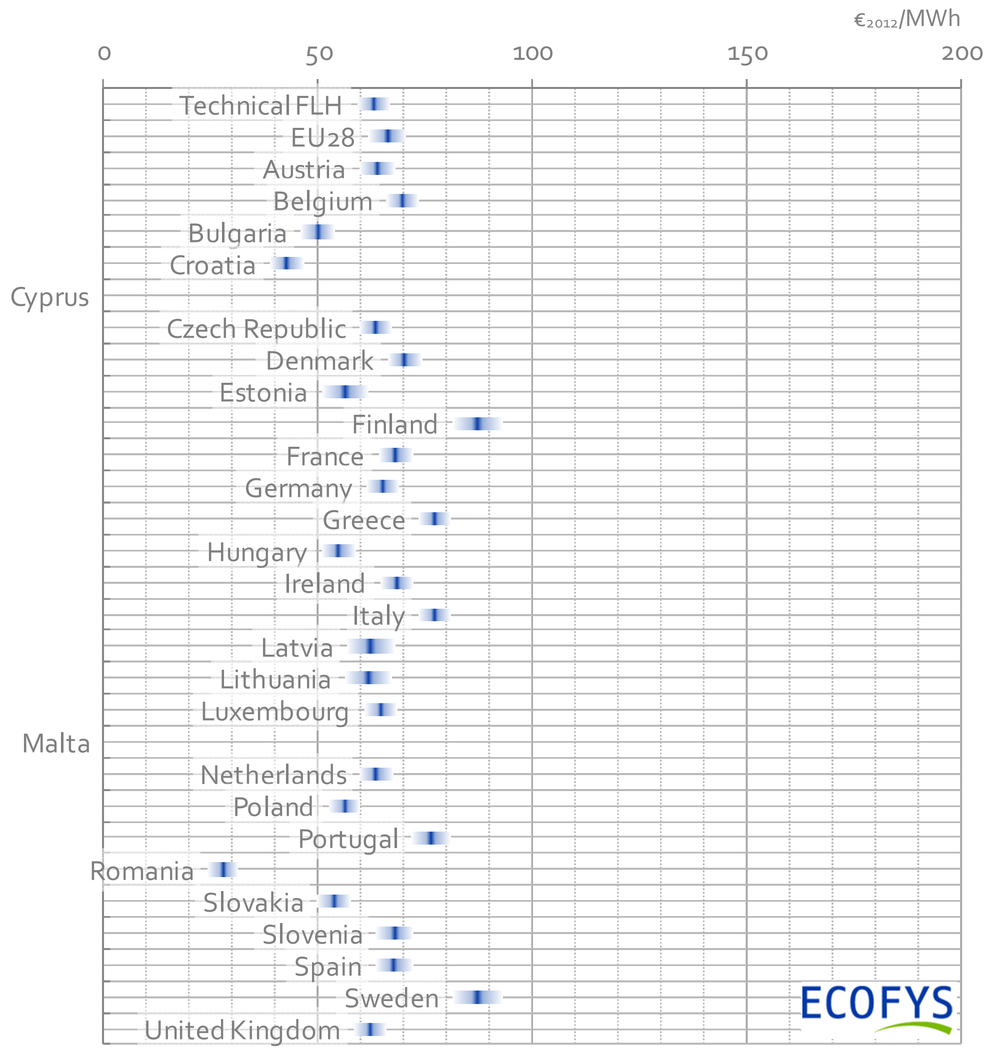

Figure A4-27: Levelised cost of heat in the EU28 Member States from domestic gas-fired boilers (condensing). Member States to which the technology is not applicable are indicated on the left side of the chart.

No natural gas is consumed in Cyprus or Malta. The costs in Sweden and Finland are relatively high because of a combination of high fuel prices and high capital costs in Northern Europe: houses in Northern Europe are relatively well insulated and require less capacity. This increases the specific investment cost (€ per kW) and thus the costs of the produced heat.

Note that the bandwidths, reflecting capital cost differences between small and large dwelling types, are relatively small. This is because fuel costs are the main driver of the levelised cost, despite significant differences in capital cost per unit of heat produced between small and large dwellings in a given member state.

A4.3.24 Domestic gas-fired boilers

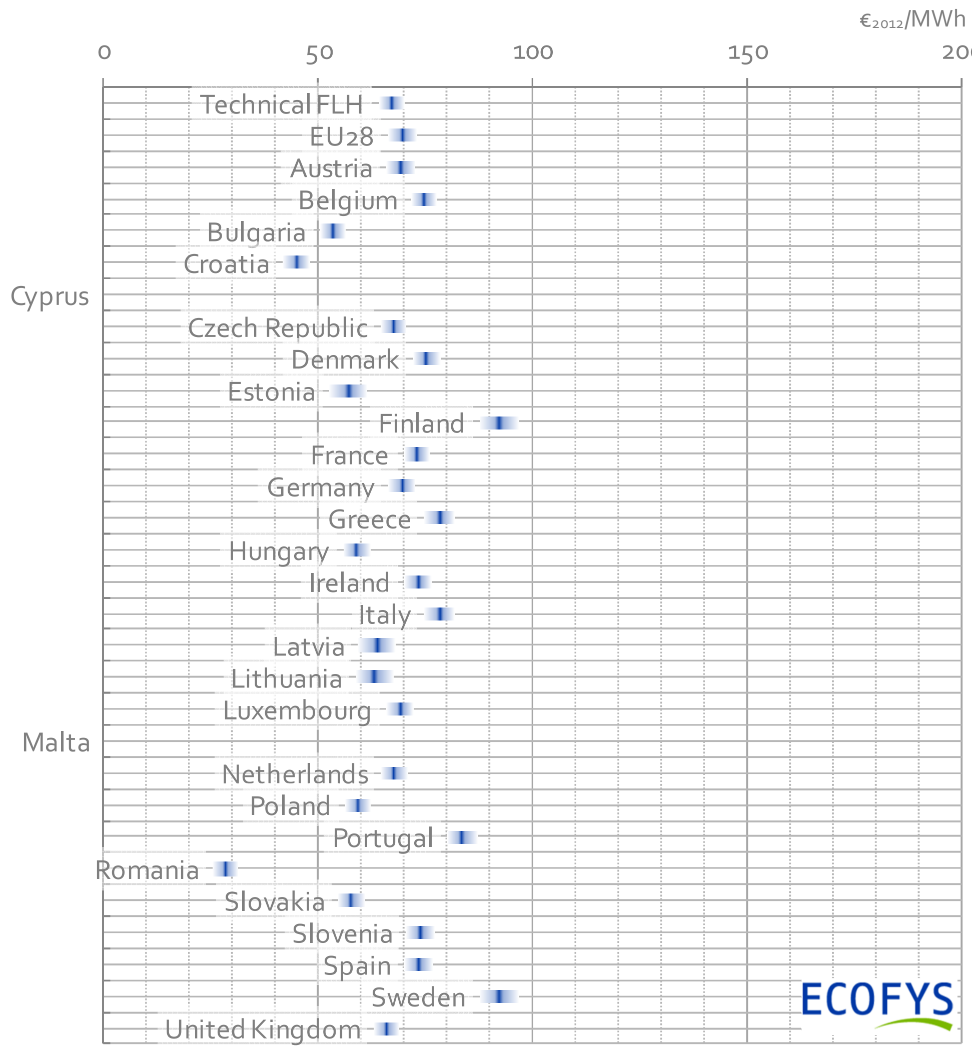

Figure A4-28: Levelised cost of heat in the EU28 Member States from domestic gas-fired boilers. Member States to which the technology is not applicable are indicated on the left side of the chart.

Note that the bandwidths, reflecting capital cost differences between small and large dwelling types, are relatively small. This is because the fuel cost are the main driver of the levelised cost, despite significant differences in capital cost per unit of heat produced between small and large dwellings in a given member state.

A4.3.25 Domestic wood-pellet-fired boilers

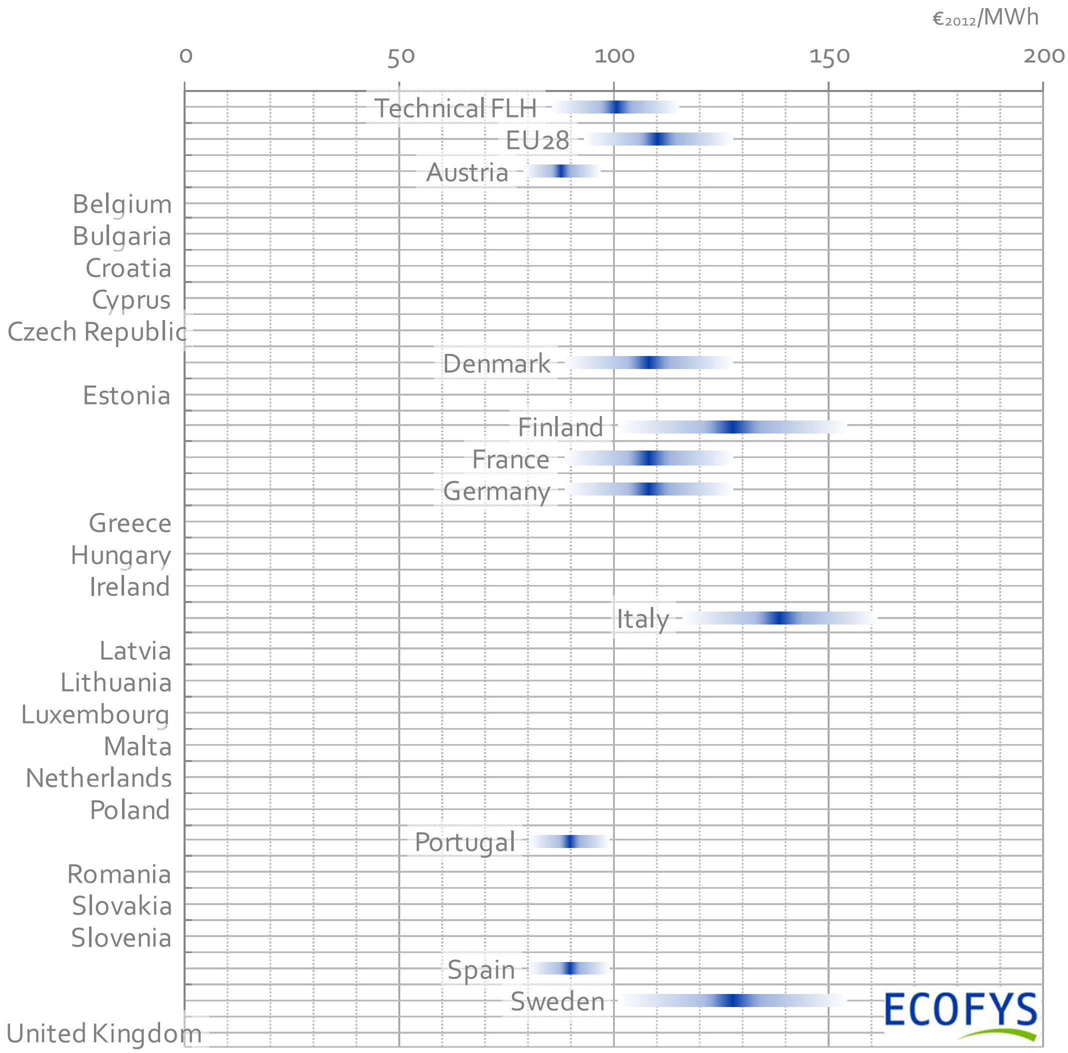

Figure A4-29: Levelised cost of heat in the EU28 Member States from domestic wood-pellet-fired boilers. Member States to which the technology is not applicable are indicated on the left side of the chart.

Pellets are not consumed in all MS, so the levelised costs are provided for a limited number of countries. Biomass pellets are not the only biomass source for domestic heating and the levelised costs shown here are not representative for residential biomass consumption in general. The costs in Sweden and Finland are relatively high, this is caused by high capital costs in northern Europe: houses in Northern Europe are relatively well insulated and require less capacity. This increases the investment cost per kW and the costs of the produced heat. The high investment costs, combined with limited utilisation levels also result in high levelised costs in Italy.

A4.3.26 Domestic heat pumps

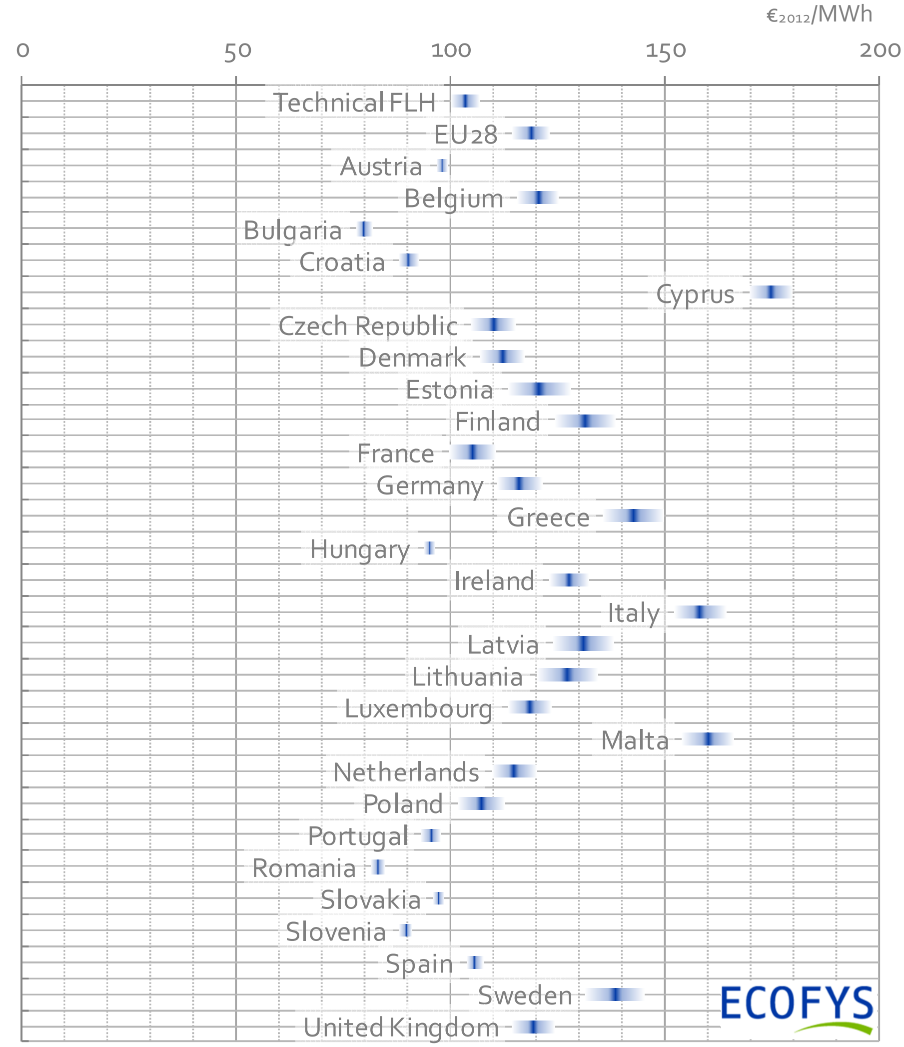

Figure A4-30: Levelised cost of heat in the EU28 Member States from domestic heat pumps. Member States to which the technology is not applicable are indicated on the left side of the chart.

Because of the warmer climate and associated limited utilisation levels, the levelised cost of heat from heat pumps are highest in Cyprus, Italy, Malta and Greece.

A4.3.27 Domestic solar thermal installations

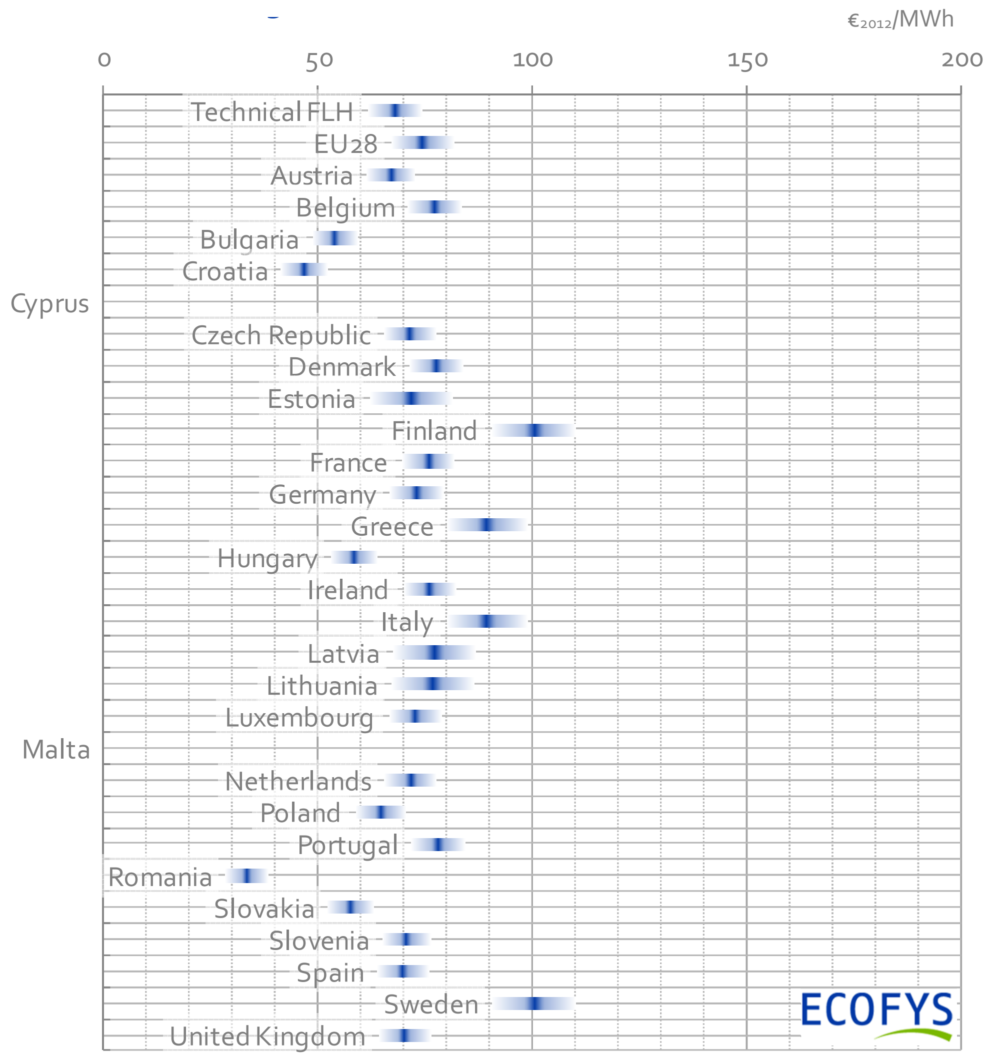

Figure A4-31: Levelised cost of heat in the EU28 Member States from domestic solar thermal installations. Member States to which the technology is not applicable are indicated on the left side of the chart.

Similarly to other domestic heating technologies, the high levelised costs in Finland and Sweden are caused by high investment costs and low irradiation for solar thermal production.

A4.3.28 Industrial steam boilers

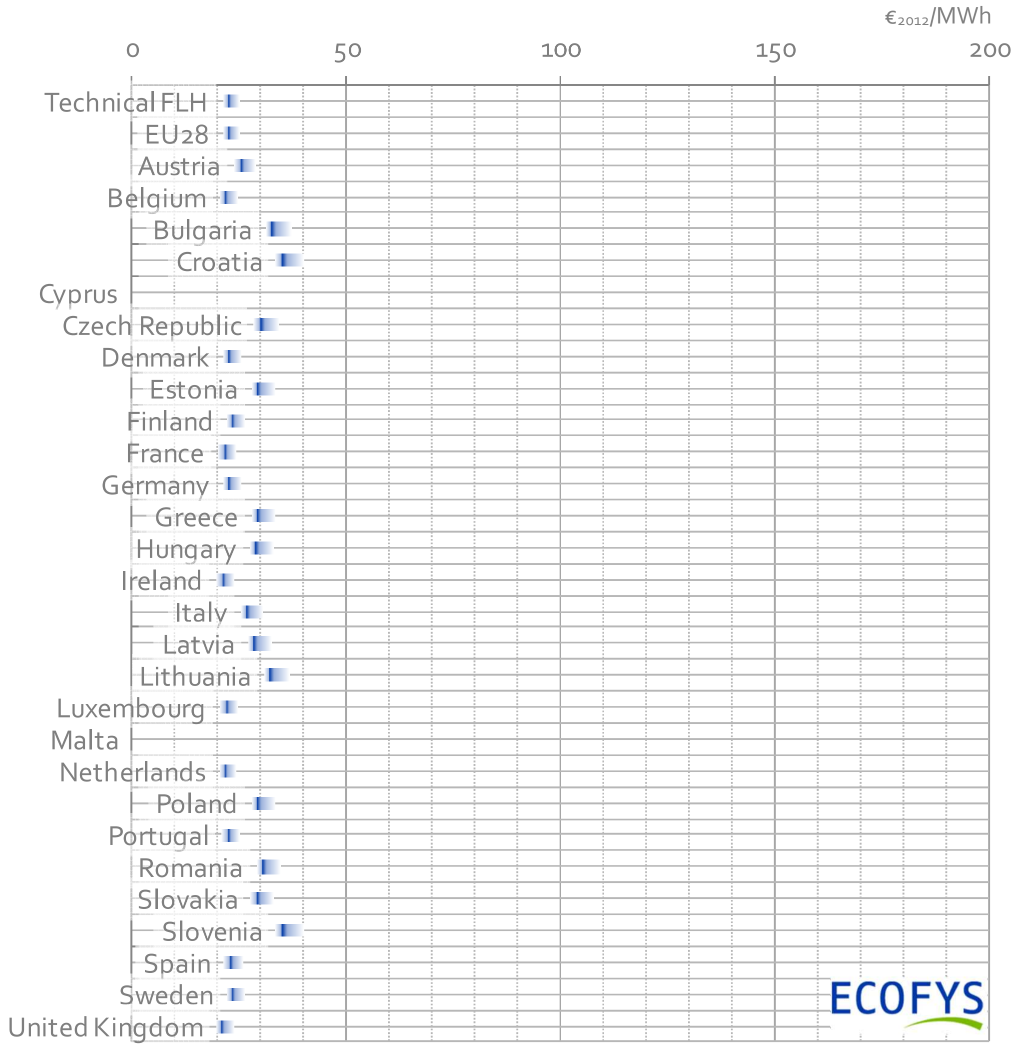

Figure A4-32: Levelised cost of heat in the EU28 Member States from industrial steam boilers. Member States to which the technology is not applicable are indicated on the left side of the chart.

A4.3.29 Marginal cost of district heating in the EU28

Marginal costs are based on fuel costs and average efficiencies in the EU28, therefore waste heat and solar thermal have zero marginal costs. For geothermal district heating, electricity costs of the pumps are included in the marginal costs, assuming a COP (Coefficient of Performance) of 15. For biomass district heating, the use of biomass pellets is assumed.

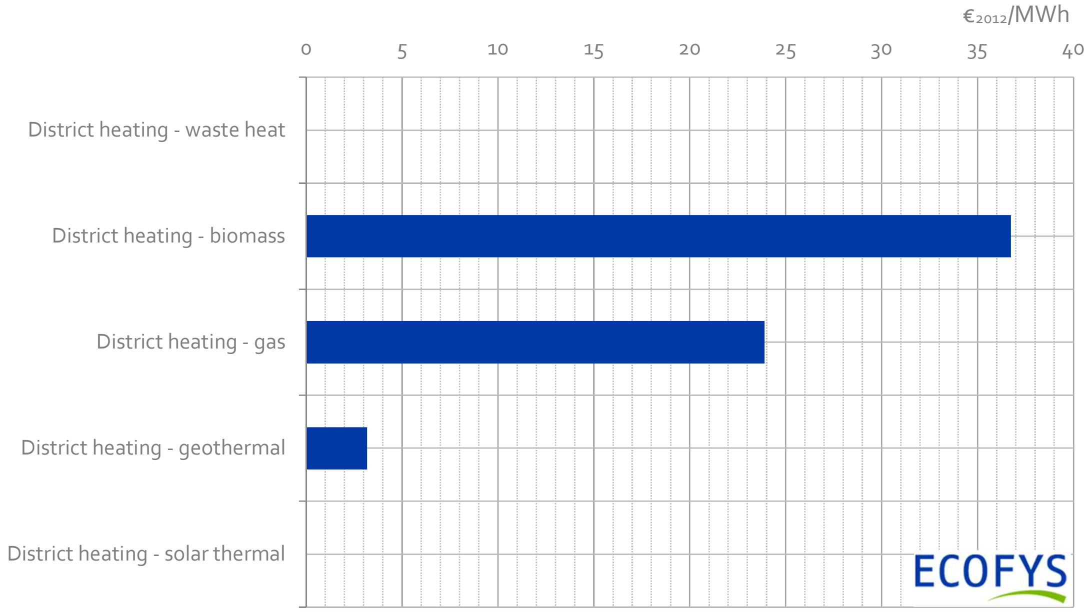

Figure A4-33: Marginal cost of five district heating technologies in the EU28.

A4.4 Grid infrastructure capital and O&M costs

Figure A4-34 and Table A4-14 show the annual expenditures for the electricity transmission network. In Table A4-14, notes are included to highlight where the figures given also include distribution network expenditures. In general, the expenditures are in line with the level of generation in a particular country, although some figures (for example Greece) look large compared to their size. Similar figures for the gas transmission network are shown in Figure A4-35 and Table A4-15.

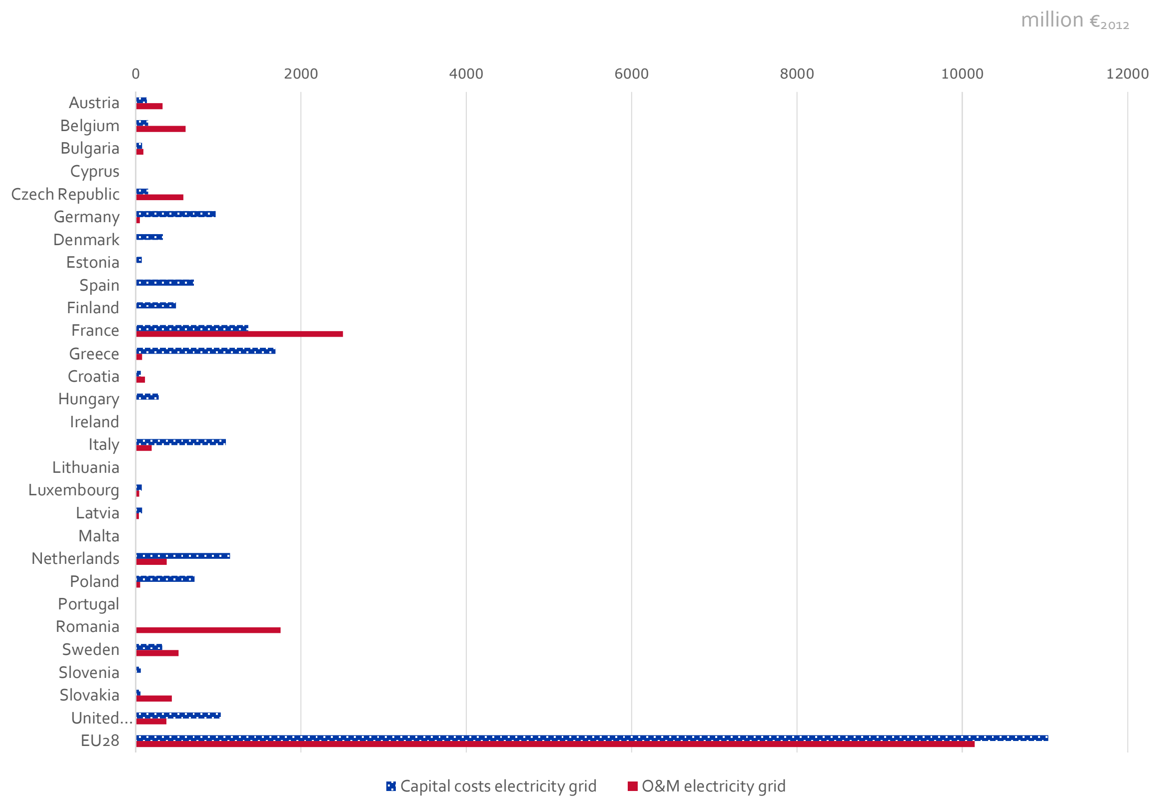

Figure A4-34: Annual expenditures in 2012 for the electricity transmission network M€$_{2012}$

Table A4-14: Capital and operation and maintenance costs (2012) for the electricity transmission network M€$_{2012}$

	Capital costs electricity grid	O&M electricity grid	Notes
Austria	136	326	
Belgium	150	605	
Bulgaria	76	95	
Cyprus	0	0	
Czech Republic	150	575	
Germany	967	49	
Denmark	330	0	
Estonia	74	5	
Spain	706	0	
Finland	487	0	*Includes O&M*
France	1363	2507	
Greece	1691	79	*Reported as transmission only*
Croatia	64	111	
Hungary	279	0	*Includes distribution and capital and O&M reported together*
Ireland	0	0	
Italy	1090	193	
Lithuania	0	0	
Luxembourg	75	43	
Latvia	78	38	*Includes distribution*
Malta	0	0	
Netherlands	1141	378	*Includes distribution*
Poland	710	54	*Includes distribution*
Portugal	0	0	
Romania	0	1750	
Sw eden	323	520	
Slovenia	63	0	
Slovakia	58	439	
United Kingdom	1027	371	
EU28	11038	10151	

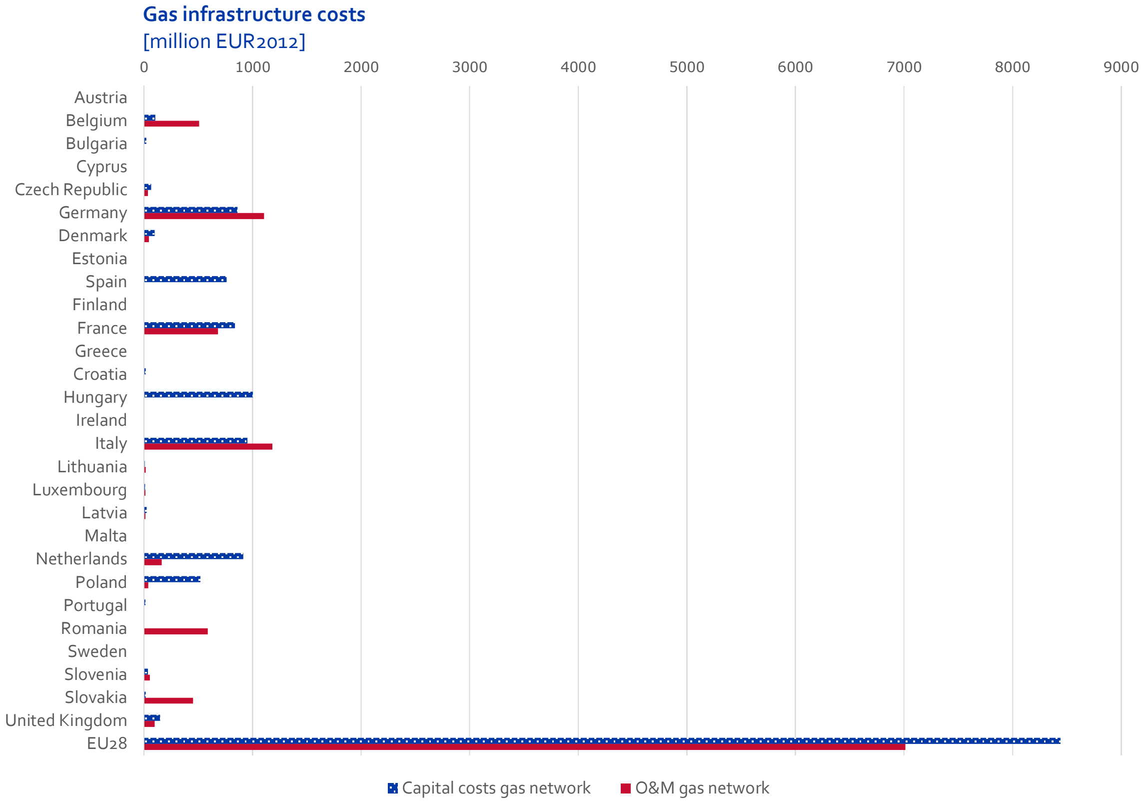

Figure A4-35: Annual expenditures in 2012 for the gas transmission network M€2012

Table A4-15: Capital and operation and maintenance costs (2012) for the gas transmission network M€$_{2012}$

	Capital costs gas network	O&M gas network	Notes
Austria	0	0	
Belgium	106	506	
Bulgaria	23	0	
Cyprus	0	0	
Czech Republic	68	38	
Germany	862	1105	
Denmark	100	45	
Estonia	0	0	
Spain	761	0	
Finland	4	0	
France	840	681	
Greece	0	0	
Croatia	16	0	
Hungary	1004	0	Includes distribution
Ireland	0	0	
Italy	954	1183	Includes distribution
Lithuania	8	14	
Luxembourg	10	13	
Latvia	26	13	
Malta	0	0	
Netherlands	915	163	Includes distribution
Poland	520	39	Includes distribution
Portugal	12	0	
Romania	0	587	
Sweden	0	6	
Slovenia	36	56	
Slovakia	16	454	
United Kingdom	149	98	
EU28	8441	7013	

Annex 5 Review of literature on subsidies in the EU

A5.1 Literature on interventions

The objective of this chapter is to provide an overview of the literature on public interventions for fossil fuels to date, and of the main common approaches to quantify their value. This chapter does not intend to give a complete inventory of all fossil fuel subsidies in and/or outside the EU28.

In recent years two major studies on public interventions for fossil fuels were published that cover almost all countries of the European Union. In 2013, the OECD published an updated version of its 2011 report 'Inventory of estimated budgetary support and tax expenditures for fossil fuels'. This study covers all 28 European Member States, except Malta and Croatia. In the same year, the IMF published its study 'Energy subsidy reform: lessons and implications', covering all 28 EU Member States. These two studies use different approaches, both regarding the definition of subsidies and in methodology.

Further reports on public interventions have been published for smaller groups of countries and for single countries, partly depending on the data availability of these countries. The results of all studies have to be viewed in the context of the different approaches. The following sections provide an overview on the common approaches of defining and quantifying public interventions for fossil fuels. Besides the two major EU-wide studies, other individual Member State studies are included where relevant.

A5.2 Common approaches for measurement of public interventions

There are different approaches in quantifying the value of public interventions for fossil fuels. Some of them are based on the same framework and differ only slightly and some use completely different basic conditions. This section gives an overview on the main common approaches: the price-gap approach, the integrated approach and the transfer measurement approach.

Price-gap approach
The price-gap approach is the most widely applied methodology for quantifying subsidies, used for instance by IEA, UNEP, OECD, IMF and various other authors[22]. The approach is based on a calculation of the gap between domestic energy and fuel prices and a reference or benchmark price. The reference price is the efficient free market price indicating the absence of subsidies[23]. Thus, a gap between the prices is an indication of the size of public interventions.
The advantage of the price-gap approach is that public interventions can be estimated using relatively small data sets. However, the outcome is highly dependent on the methodology for setting the efficient price level as the benchmark. Known concepts are for instance to base the price on estimated long-run marginal costs or to base it on estimated average cost of production.

[22] IEA, OPEC, OECD, World Bank. (2010). Analysis of the scope of energy subsidies and suggestions for the G-20 initiative.
[23] Oxford Energy Associates (2013). Energy Subsidies in the UK.

The public interventions that are reflected by the price-gap approach depend on the components included in the benchmark price, e.g. if common taxes (e.g. VAT for end consumers) are included in the reference price, tax exemptions will be covered by the price-gap approach. Furthermore, externalities like costs related to CO_2 emissions can be included. The price-gap approach will reveal the combined effect of public interventions on energy prices. Drawbacks of this approach are that public interventions that do not affect the final price cannot be covered (for example, grants and R&D support to generators will not lead to changed prices) and that it is not possible to disaggregate the effects of individual interventions[24].

Integrated approach

The integrated approach is based on the so-called Producer Support Estimate (PSE) and the Consumer Support Estimate (CSE) framework that provides insights into both kinds of public interventions. This approach comprises the price-gap approach and the measurement of public interventions based on transfers from governments to both consumers and producers. It thereby combines direct financial transfers as well as transfers generated between producers and consumers (and vice-versa) as a result of government policies.

The PSE measures the (annual) monetary value of transfers from consumers and taxpayers to producers, measured at the producer property and arising from policy measures that support producers. This support is achieved by creating a gap between domestic market prices and border prices of products (often commodities) and in fewer cases also services.

The CSE measures the annual monetary value of transfers from taxpayers - to consumers of the commodity, arising from policy measures that support consumers by reducing the actual price the consumer has to pay. To measure the CSE, price transfers from consumers that include transfers to both domestic producers and the government are subtracted.

The Effective Rate of Assistance (ERA) approach is based on the PSE-CSE framework. The approach is an extension of the concept of the Effective Rate of Protection, which was developed in the 1960s. Effective rates apply to activities and measure the net assistance provided by tariff protection. Thus, for instance tariff protection to local production caused by import taxes is taken into account. The ERA additionally includes non-border interventions like input taxes and subsidies, special tax arrangements or production bounties[25].

The OECD adopted the ERA approach, quantifying a producer and a consumer support estimate as well as a general service support estimate (GSSE). GSSE transfers do not affect producer revenue or consumer expenditures in the short term, but does in the long-term. This includes for instance research and development, marketing and promotion or infrastructure[26].The resulting transfers of the PSE are valued at the industry's value added[27].

[24] IISD (2009). Measuring Energy Subsidies Using the Price-Gap Approach: What does it leave out?
[25] Industry Commission Australia (1992). The Measurement of Effective Rates of Assistance in Australia, Working Paper for the Organisation for Economic Cooperation and Development (OECD).
[26] Oxford Energy Associates (2013). Energy Subsidies in the UK.
[27] See IISD (2011). Subsidies and External Costs in Electric Power Generation: A comparative review of estimates.

Transfer measurement approach

The transfer measurement approach, also known as the programme specific approach, quantifies the value of specific government programmes, i.e. it attempts to measure the value that is transferred to stakeholders from a particular government intervention. The transfer measurement approach captures the value of government measures that benefit (or tax) a particular sector, whether these benefits end up with consumers (as lower prices) or producers (through higher revenues).

The advantage of this approach is that public interventions that do not have an effect on the end-market price can be made visible and quantified. A drawback of this approach is that it is very data intensive and the outcome is highly dependent on the programmes that are covered in the analysis.

A5.2.1 EU-wide studies – OECD and IMF

OECD 2013

The OECD (2013) study on public interventions[28] covers all 28 EU Member States except Malta and Croatia. It is an update and extension of the 2011 OECD report[29], which covered only 10 EU Member States. The 2013 study presents 2011 data. The OECD distinguishes between subsidies that are related to energy consumption and those that are related to energy production.

The approach and methodology used by the OECD for estimating tax expenditures is based on the price-gap approach and the PSE-CSE framework. Besides coal and gas, the study covers the petroleum sector and the so-called general services support sector.

The OECD (2011, 2013) divides subsidies into five groups as mentioned previously: direct transfer of funds, tax revenue foregone, other government revenue forgone, transfer of risk to government and induced transfers. The majority of support mechanisms identified in the inventory are tax expenditures, and are measured with reference to a benchmark tax treatment that is generally specific to the country in question. Tax expenditures are defined as "a relative measure of the amount by which tax revenues are lower as a result of some preference than they would be under the benchmark rules of the particular national tax system". The OECD does not include externalities in its report.

The OECD identifies public interventions for fossil fuels of the EU of € 39 billion, including the petroleum sector, which accounts for € 25 billion. The consumption of natural gas is subsidised by nearly € 5 billion, whereas subsidies related to coal are valued at € 6.1 billion (€ 3.5 billion for production, € 2.6 billion for consumption).

The scope of the OECD study is limited. The study only includes measures induced by national Governments to the extent to which governments report on the existence and value of support mechanisms: direct budgetary transfers and tax expenditures related to fossil fuels. Measures at the sub-national level in federal counties are only included on a selective basis. Furthermore, other forms of support — notably those provided through risk transfers, concessional credit, injections of funds (as equity) into state-owned enterprises, and market price support — are not quantified. Since the study relies on the existence of published government data, there is significant difference in the level of detail of the country data.

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[28] OECD (2013). Inventory of Estimated Budgetary Support and Tax Expenditures for Fossil Fuels 2013. Available at http://www.oecd.org/site/tadffss/

[29] OECD (2011). Inventory of estimated budgetary support and tax expenditures for fossil fuels.

IMF 2013

The IMF (2013) study on public interventions[30] covers all 28 EU Member States. The study takes into account both consumer and producer subsidies. The IMF uses the same price-gap approach as the OECD to quantify the value of public interventions. A benchmark price is set for each product and subsidies occur when the prices paid by consumers are below the benchmark price (consumer subsidy) or when prices received by suppliers are above the benchmark price (producer subsidy).

The study comprises subsidies for coal, gas, petroleum and electricity. For each Member State and energy sector, pre-tax and post-tax subsidies are quantified. Pre-tax subsidies occur when energy consumers pay less than the supply and distribution cost of energy, i.e. the price consumers pay is below the international price or the cost-recovery price (if the good is not traded internationally). Post-tax subsidies are calculated with a benchmark price including a value for efficient taxation. Thus, post-tax subsidies are the pre-tax subsidies of the product plus all tax subsidies. Following the definition of IMF (2013), tax subsidies include tax exemptions and social and environmental costs. Post-tax subsidies occur, if the after-tax energy price is below the level consistent with efficient taxation that is based on uniform rates of consumer taxes like VAT across all goods and compensatory taxes accounting for external costs of energy.

IMF (2013) uses data by IMF staff, OECD and Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) for subsidies for petroleum products. Interventions for natural gas and coal are mostly calculated from IEA data and partly from OECD. The subsidies for the electricity sector are derived from different sources of IEA, World Bank and IMF itself.

Externalities included in post-tax subsidies comprise environmental costs (e.g. global warming) and social costs (e.g. effects of pollution on public health). Damages from global warming are valued at a price of $ 25/ton CO_2. In contrast, OECD (2013) does not include any externalities.

IMF (2013) shows subsidies as a percentage of GDP for each country. Transformed into absolute values in Euros on basis of GDP figures from Eurostat, the IMF values total fossil fuel subsidies of the 28 EU Member States at nearly € 64 billion. The highest share of fossil fuel post-tax subsidies is related to the use of coal with a total of € 38 billion, followed by gas with €22 billion. However, due to the facts that negative environmental and health externalities are not or only slightly accounted for in taxes and energy products are usually taxed lower than other products, pre-tax subsidies are much lower than post-tax subsidies. Thus, pre-tax coal subsidies of the 28 EU Member States have a share of less than 10 percent (€ 2.8 billion) of the post-tax coal subsidies.

The quantified values of subsidies of IMF (2013) and OECD (2013) cannot be compared, because IMF values subsidies pre-tax and post-tax including externalities whereas OECD values subsidies including tax exemptions but excluding externalities.

[30] IMF (2013) Energy Subsidy Reform: Lessons and Implications.

NERA 2014 for OGP

In this study for the Oil and Gas producers, NERA Economic Consulting analysed the taxation and subsidy regimes applying to oil, gas, coal, wind and solar power in the EU28 and Norway during the period 2007 - 2011[31]. Their approach is to estimate the full range of financial flows to and from energy, including Government revenues e.g. tax revenues, Government expenditure and mandated transfers e.g. support schemes funded by consumer levies. The scope of the study included oil production and transport energy use and Norway, so a direct comparison with the results here is not possible.

A5.3 Studies for individual Member States

Over the last couple of years, several studies have been conducted that quantify fossil fuel subsidies for individual countries. These include studies for the Western Balkan countries (UNDP 2011), Germany (Green Budget Germany 2013), the Netherlands (Ecofys 2011) and various other EU Member States (e.g. IVM 2013).

The country studies for Germany and the Netherlands follow a bottom-up approach, evaluating programme specific measures and instruments, including indirect subsidies and focussing on both the consumer and the producer side. The multiple country studies for the Western Balkan countries and several EU Member States follow a more top-down approach by making use of the price-gap method. All studies take externalities into account.

In 2011, Ecofys[32] conducted a study on public interventions in the Dutch energy market covering fossil fuels, renewable energy and energy efficiency. The aim of this study was to evaluate the efficiency and effectiveness of the policies. The study covers 53 different public interventions. External costs like health costs are included.

UNDP[33] published a study in 2011 on fossil fuel subsidies in the Western Balkans. The study develops a price-gap approach and estimates the value of public interventions as a percentage of the GDP. The study assumes, that the consumption of fossil fuels and GDP are related, so that the approach avoids exchange rates and power purchase parities to have effects on the results. The approach uses a benchmark price covering the full marginal cost of fossil fuels including externalities as environmental impacts.

The IVM Institute for Environmental Studies[34] conducted a study in 2013 quantifying the value of public interventions of the six EU Member States that were not covered in the OECD (2011) study. The methodology and approach are adapted to the OECD (2011) report. The updated and extended report of the OECD from 2013 covers these countries as well.

Research undertaken by the think tank Green Budget Germany[35] quantifies the value of public interventions and externalities for the period from 1970 - 2012. Studies covering historic subsidies

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[31] Energy Taxation and Subsidies in Europe: A Report on Government Revenues for Fossil Fuels and Renewables in the EU and Norway, report for the International Association of Oil and Gas Producers. http://www.nera.com/67_8572.htm

[32] Ecofys (2011). Government Interventions in the Dutch energy market.
Ecofys (2012). Overheidsingrepen in de Energiemarkt – Onderzoek naar het Nederlandse speelveld voor fossiele, duurzame en kernenergie.

[33] UNDP (2011). Fossil Fuel Subsidies in the Western Balkans.

[34] IVM (2013). Budgetary support and tax expenditures for fossil fuels – An inventory for six non-OECD EU countries.

[35] Green Budget Germany (2012).The full costs of power generation - A comparison of subsidies and societal cost of renewable and conventional energy sources.

over many decades are rare and this study is the only one used here presenting historical figures for subsidies.

The state support in 2012, expressed by financial aid and tax incentives is valued at € 7.1 billion for fossil fuels plus €7.8 billion for nuclear whereas external costs for electricity already account for € 26.1 billion for fossil fuels plus € 9.0 billion minimum for nuclear. Besides looking at coal, natural gas and nuclear, the study covers data on renewable energy that have been subsidised in 2012 with € 11.1 billion. It quantifies the total value of subsidies and the share of the electricity sector. Furthermore, the study includes the calculation of a surcharge for conventional energy to compare subsidies spend on conventional energy sources with the current subsidies for renewable energy.

The Oxford Energy Associates (2013) analysed the energy subsidies in the UK[36] using the transfer measurement approach. Besides subsidies to fossil fuels, namely oil, coal and gas, they calculated UK subsidies to nuclear, renewable energies, the electricity sector and research and development in general. They based their analysis on fossil fuels on data from OECD (2012). For nuclear they estimated the government funding for decommissioning and clean-up costs (historic and future) as well as further subsidies regarding the operation of plants. The analysis on renewables includes the old non-fossil fuel obligation scheme, as well as the Renewable Obligation scheme and Feed-in Tariffs. The subsidies to the electricity sector are mainly based on tax reductions.

Fiore (2006)[37], and Faure and Fiore (2009)[38] have estimated the subsidy a typical French nuclear power plant (NPP) receives, applying the French liability limit of € 700 million. They vary the cost of major accidents between €10 and €100 billion, probability of a major accident between 10^{-4} and 10^{-6} per Reactor Year (Ry) and share of risk-aversion premium between 5% and 10%, and arrive at a subsidy range of € 0.019-2.800 million per Ry. Because the calculation is quite complex, expanding the approach for all other MSs and the potential damage range detailed above is out of the scope of this project. Rather, this range is applied for all European reactors to get a feel for the order of magnitude. There are 131 European nuclear reactors,[39] which means that in the EU the yearly nuclear liability subsidy is ranging from € 2.49-367 million (131 * 0.019-2.800). Assuming that a typical European nuclear reactor has an average capacity load of 75%, produces on average 6.1 TWh/y[40]. Therefore based on the above approach, the typical European nuclear reactor receives € 0.0031-0.46/MWh nuclear liability subsidy.

Cour des comptes (2014) evaluates the cost of electricity generation of NPPs in France[41]. The study analyses different costs, namely exploitation costs, maintenance investments for the existing NPPs, provisions for waste management and for decommissioning and economic rents. The provisions for waste management and decommissioning are based on the charges producers have to pay. External costs are only included if they have been internalised by charges or fixed payments of the producers in case of a nuclear accident. In total, the costs for nuclear power generation in 2013 have been about €24 billion or about €60/MWh respectively.

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[36] Oxford Energy Associates (OEA) (2013). Energy Subsidies in the UK.
[37] Karine Fiore (2006). The nuclear liability limit in the OECD conventions. http://www.faee.fr/files/file/aee-se/meilleurs-papiers/2007/kfiore_nuclear.pdf
[38] Michael Faure and Karine Fiore (2009). An Economic Analysis Of The Nuclear Liability Subsidy. Pace Environmental Law Review. Volume 26 Issue 2. http://digitalcommons.pace.edu/cgi/viewcontent.cgi?article=1025&context=pelr
[39] Data from: http://www.euronuclear.org/
[40] http://ec.europa.eu/energy/nuclear/consultations/20130718_powerplants_en.htm
[41] Cour des comptes (2014). Le coût de production de l'électricité nucléaire – actualisation 2014.

The Union of Concerned Scientists (2011) evaluated the subsidies to US NPPs[42]. The study distinguishes between subsidies to existing and new reactors. The subsides are categorised in output-linked support, subsidies to factors of production, policies affecting the cost of intermediate inputs, subsidies to security and risk management and subsidies to decommissioning and waste management. The total subsidies to the nuclear power industry are given in relation the electricity output of a plant. The ongoing support for existing reactors is estimated at 0.74 to 5.77 $ct/kWh, subsidies for new reactors at 4.20 to 11.42 $ct/kWh. The range is partly due to assumptions on external costs for a nuclear accident. These costs are estimated to 0.1 $ct/kWh to 2.5 $ct/kWh.

The CEER published a study in 2013 evaluating the support to RES in European countries[43]. The analysis was done using the transfer mechanism approach. In detail, the CEER conducted a survey in 2012 about types and amounts of supports for RES, answered by 24 European countries. The CEER evaluates the amount of energy generated that is supported and the level of support for each technology and country.

Frontier Economics conducted a study in 2013 to compare the support levels for onshore wind of different countries[44]. They analysed the subsidies in all countries that had an installed capacity of at least 1,000 MW in 2011. The study evaluates average and initial support levels as well as net support levels based on local market value of wind. All support levels are given dependent on electricity output.

The comparison of the support levels of different countries is only partly given, because the amount of years the support is guaranteed differs. Countries with long guaranteed support times may thus have lower support prices.

A5.4 Overview of main results in literature

Table A5-1 summarises the differences in methodology and scope of the literature reviewed. Table A5-2 presents the evaluated financial amounts of public interventions for fossil fuels, including the OECD (2013) and IMF (2013) reports. Table A5-3 shows the findings of single Member State studies on public interventions on nuclear energy and Table A5-4 highlights the main findings on public interventions on renewable energies.

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[42] Union of Concerned Scientists (2011). Nuclear Power: Still not viable without subsidies.
[43] CEER (2013). Status Review of Renewable and Energy Efficiency Support Schemes in Europe.
[44] Frontier Economics (2013). International support for onshore wind – a report prepared for DECC.

Table A5-1: Overview of the methodology of studies quantifying the value of public interventions for fossil fuels in EU Member States

Study	Scope	Approach	Subsidies for...	Measures included
OECD 2013	26 EU Member States	Price-gap and integrated approach	Coal, natural gas, petroleum, general services support	Mainly tax exemptions
IMF 2013	All 28 EU Member States	Price-gap approach	Coal, natural gas, petroleum, electricity	Pre-tax subsidies, post-tax subsidies including externalities and tax breaks
UNDP 2011	Western Balkans	Price-gap method, marginal societal cost	Coal, natural gas, electricity, petroleum, district heating	All interventions leading to a domestic price below marginal cost, externalities
Ecofys 2011	The Netherlands	Transfer measurement and integrated approach, marginal societal cost	Coal, natural gas, petroleum	Direct subsidies, tax exemptions, soft loans, price regulation, quota obligations, externalities
Green Budget Germany 2012	Germany	Transfer measurement approach	Coal, natural gas, nuclear, electricity, renewables	Direct state aid, tax benefits, externalities
IVM 2013	Bulgaria, Cyprus, Latvia, Lithuania, Malta, Romania	Price-gap and integrated approach	Coal, natural gas, petroleum, general services support	Mainly tax exemptions
Oxford Energy Associates 2013	United Kingdom	Transfer measurement approach	Oil, coal, natural gas, nuclear, renewables, electricity, R&D	Direct subsidies, tax exemptions, liabilities,
Union of Concerned Scientists 2011	United States of America	Transfer measurement approach	Nuclear	Direct subsidies, tax exemptions, soft loans, price regulation, liabilities, externalities
CEER 2013	Europe	Transfer measurement approach	Renewables	Direct subsidies, tax exemptions, price regulation, soft loans,
Frontier Economic 2013	Countries with 1 GW installed wind onshore capacity 2011	Transfer measurement approach	Wind onshore	Direct subsidies, tax exemptions

Table A5-2: Overview of the results of studies quantifying the value of public interventions for fossil fuels in EU Member States in € billion per year excluding non-internalised externalities

Country	OECD 2013		IMF 2013[45](Post-tax)		Country specific study		
	Coal	**Gas**	**Coal**	**Gas**	**Coal**	**Gas**	**Source**
Austria	0.1	0.213	0.48	0.36			
Belgium		0.1	0.33	0.78			
Bulgaria		0.0*	0.84	0.10	0.00**	0.00**	IVM 2013
Croatia			0.10	0.15	2.1 – 2.5[46]		UNDP 2011
Cyprus			0.00	n.a.	0.00	0.00	IVM 2013
Czech Republic	0.5*	0.8*	2.13	0.42			
Denmark	0.9*		0.43	0.19			
Estonia	0.0		0.42	0.02			
Finland	0.2	0.1	0.62	0.13			
France	0.0	0.3	1.40	2.00			
Germany	2.1	0.5	12.01	3.65	6.5	0.6	Green Budget Germany 2012[47]
Greece	0.0		0.92	0.17			
Hungary	0.0*	0.0*	0.30	0.58			
Ireland	0.1		0.36	0.21			
Italy		0.1	1.74	3.63			
Latvia		0.0*	0.02	0.08	0.00**	0.04**	IVM 2013
Lithuania		0.1*	0.03	0.12	0.00**	0.05**	IVM 2013
Luxembourg			0.01	0.05			
Malta			n.a.	n.a.	No data	No data	IVM 2013
Netherlands		0.1	1.02	1.86	5.7[48]		Ecofys 2011
Poland	1.2*		6.82	0.70			
Portugal	0.0		0.26	0.21			
Romania	0.1*		0.72	0.55	0.09**	0.00**	IVM 2013
Spain	0.3		1.78	1.36			
Slovakia	0.1	0.1	0.43	0.26			
Slovenia	0.0	0.0	0.18	0.03			
Sweden	0.4*	0.7*	0.27	0.04			
United Kingdom	0.0*	1.9*	3.90	4.07	0.1*	4.2*	Oxford Energy Associates 2013
EU-28	**6.1**	**4.9**	**37.51**	**21.73**			

* National currencies are converted to € using average 2011 exchange rates.

** National currencies are converted to € using exchange rates given in report. Total values calculated with most recent data, if data on more years was given.

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[45] IMF (2013) post-tax values include rough estimates for externalities. Originally the values are presented as a percentage of GDP and were transformed into € billions by Ecofys on the basis of GDP figures from Eurostat.

[46] Originally expressed as percentage of GDP (5 – 6%). Total value in € billions calculated, based on GDP figures from Eurostat. Number includes besides coal and gas subsidies also crude oil, direct electricity and district heating subsidies and environmental costs.

[47] Updated data based on Green Budget Germany (2012).

[48] Value includes at least €1.9 billion for liquid fuels.

Table A5-3: Overview of the results of studies quantifying the value of public interventions for nuclear energy in EU Member States in € billion per year excluding non-internalised externalities

Country	Green Budget Germany 2012	Ecofys 2011	Oxford Energy Associates 2013
Germany	7.8		
Netherlands		0.01	
United Kingdom			2.6

Table A5-4: Overview of the results of studies quantifying the value of public interventions for renewable energy systems in EU Member States in € billion per year excluding non-internalised externalities

Country	CEER 2013	Green Budget Germany 2012	Ecofys 2011	Oxford Energy Associates 2013
Austria	0.38			
Belgium	0.73			
Czech Republic	0.49			
Estonia	0.04			
Finland	0.01			
France	1.51			
Germany	9.51	11.1		
Hungary	0.25			
Italy	3.43			
Luxembourg	0.01			
Netherlands	0.69		1.5	
Norway	0.02			
Portugal	0.75			
Romania	0.04			
Spain	5.37			
Slovenia	0.04			
Sweden	0.48			
United Kingdom	1.44			3.5

Table A5-2 to Table A5-4 highlight that the studies show different results for public interventions. Especially the studies for the Netherlands, Croatia and Germany on public interventions on fossil fuels show higher values than the IMF and OECD studies.

There are various reasons for the differences in values and these need to be interpreted with care. In general, studies use different general approaches for the quantification. As shown in Table A5-1, studies that cover many countries tend to use the price-gap approach, because it is least data intensive. For single country studies, insights into the single country and the limited amount of public interventions allow the usage of the transfer measurement approach, given that detailed data is available. Thus, the single country studies for Germany and the Netherlands use the transfer measurement approach. However, the approaches of the other studies show differences as well, e.g. in setting the benchmark price.

Furthermore, the integration of externalities into the quantification methodology has a significant influence on the subsidy amounts calculated. Not accounting for externalities leads to lower subsidy amounts. In the studies assessed, only the OECD (2013) study does not account for externalities at all. The data given in Table A5-2 to Table A5-4 do not include externalities as well, if these were reported separately in the studies. Values of IMF (2013) and UNDP (2011) include at least some externalities. The methodology of internalising external costs differs between the studies and has a high impact on total results. Since the real costs for externalities as climate impact are not known, assumption on these costs differ significantly and the share of external costs may be very high, as shown in IMF (2013) and Green Budget Germany (2012).

Lastly, the results of the studies are highly dependent on data availability, data accuracy and estimations where no data is available.