Annex 6

Main comments from the stakeholders on the data and methodology

During the preparation of the report on energy costs and subsidies in the EU, a large number of stakeholders at EU and Member States level have been consulted. A stakeholder webinar and two stakeholder/Member State workshops were organised in order to provide the opportunity for stakeholders to express their views on the methodology chosen, the accuracy of the data collected and the results obtained.

In this annex the main methodological issues are summarised, giving a description of how the major methodological challenges and issues brought up by the stakeholders have been addressed in the final report.

Interventions and subsidies

Sectoral benchmarks for taxation

In several EU member states governments impose relatively high corporate or other taxes and levies on energy companies. In the report however, tax subsidies (i.e. exemptions) are only taken into account for corporate taxes if below the normal corporate tax rate of the industry.

Comparing the tax exemption subsidies in higher taxing countries with lower taxing countries can give strange results. In order to avoid these extreme cases the report opts for using tax exemptions compared to a sectoral benchmark in each country.

As the revenues from tax rates higher than the industrial average directly finances the general state budget, and it are not linked to internalising energy costs, we can only talk about tax subsidy if the final effective tax rate sinks below the industrial average. From the microeconomic perspective of relative market prices, the granting of a tax exemption reduces government revenues and constitutes a subsidy. This is the standard legal approach, used by the OECD as well as from a state aid, international trade and an EU taxation perspective.

The fact that a sector pays higher taxes (unrelated to the external costs it generates) does not negate the effect of a tax exemption, which necessarily changes relative energy prices and commercial behaviour. There was a divergence in views among different stakeholders, some of them prefer this approach to using actual high tax rates, but others say it is an arbitrary decision.

Netting of subsidies and revenues of the state

The energy industry pays significant taxes in national budgets, as it was shown by a recent study[1]. This NERA study follows an approach according to which energy tax revenues ("negative subsidies") are netted from actual subsidies. One may ask why the report on energy costs and subsides does not follow this approach. Comparing aggregate costs and revenues (as the NERA study did) is interesting, but not meaningful when looking at relative energy prices and the market-distorting effect of specific government interventions.

The current report for the Commission instead focusses on the true costs of the energy sector. Therefore, netting of revenues and subsidies is followed only in cases where revenues from government measures can directly be linked to external costs (e.g.: carbon taxes are deducted from the external cost of carbon). Otherwise, above average taxes imposed on the energy industry, being unrelated to the external costs the industry generates, are not subject to deduction from subsidies.

[1]Energy Taxation and Subsidies in Europe (NERA study commissioned by OGP):
http://www.nera.com/content/dam/nera/publications/archive2/PUB_OGP_0514.pdf

Deducting the tax paid by nuclear power plants by generation power from subsidies

In some of the Member States having nuclear power generation capacities a special tax is imposed on nuclear power generation. In the current report this is not considered as an item reducing the subsidies given to nuclear generation, as following the logic described in the previous point, it cannot be assumed that budget revenues from this nuclear tax are exclusively used for internalising external costs in the energy sector; revenues may also serve other government policies.

Accounting estimates for nuclear decommissioning costs

Estimated decommissioning costs vary widely across member states. Decommissioning subsidy occurs if the accumulated amount of money in the given fund collected for decommissioning purposes is not sufficient, therefore the government needs to complement it. This option is considered as historic subsidy in the study (as timing of the decommissioning is not clear due to potential lifetime extensions or political decisions might result in opting out from the use of nuclear). If the estimated costs of decommissioning falls below a pre-established threshold (per generation capacity in MWe), the difference of actual costs and this threshold is considered to be an intervention.

If currently available funds fully cover estimated decommissioning costs but the estimated costs do not cover real costs, a shortage can still arise and the government has to intervene. In this case plant operators are not making high enough pre-payment to fill up the fund for future costs. This shortage is counted as current subsidy, and detailed data are available for almost all member states having nuclear generation capacities. Given that decommissioning costs may arise in the far future, the discounting impact, converting future costs to present terms, might be low compared to the value of the project value and is not substantially impacted by the choice of applied discount rates.

The logic applied above mainly refers to nuclear plants, however, this is used for other generation sources as well (e.g.: fossil fuels or mining operations).

Calculation of historic subsidies (the impact of government risk transfer in non-liberalised markets, dividend of state owned utilities, privatisation incomes, etc.)

As direct subsidy data could not be collected for all member states looking backwards for several decades, historic subsidies are based on calculations.

Direct investment subsidies were estimated as the difference between the costs of investments carried out by state-owned energy utilities (before the liberalisation of the energy market the dominance of the national states was the case and the internal EU energy market did not exist) and those by private companies were taken into account. This was done by assuming lower weighted averages cost of capital (WACC) for state-owned companies than for the private sector before market liberalisation and hence lower levelised costs for the given technology. The difference between the two levelised costs is the government intervention (subsidy as transfer of risk).

Although some stakeholders suggested that in the state-dominated model of energy "markets", characteristic before recent market liberalisation, generation capacities were not supposed to develop freely under market conditions, the chosen methodology allows for capturing the amount of investment subsidies by comparing the recognised historical developments with investment in capacities developed under liberalised market conditions, implemented by private investors).

Privatisation of national assets cannot be fully considered as negative subsidy in the contractor's assessment. As the price difference between the sale of a private and a public asset to a private owner could be considered as subsidy, stemming from the transfer of risks in the case of the state-owned asset. This difference however is not significant compared to the asset value, and therefore the whole privatisation revenue should not be deducted from subsidies. Following a similar logic dividends paid to the state before market liberalisation cannot be fully accounted as negative subsidy either.

Indirect supports for R&D activities were taken from the IEA database and were complemented by estimations. Direct historic support for fuel generation, also impacting the current generation mix, was based on differences of import and domestic fuel production prices, taking the difference as a subsidy.

Lack of historical grid costs and subsidies

Historical subsides to investments in both generation capacities and infrastructure continue to have a significant impact on the current energy market. In contrast to generation, extracting data on grid subsidies is not an easy exercise as numerous transmission and distribution system operators (TSOs and DSOs) in different countries do not account these subsidies according to a common methodology. A major bottom up data gathering exercise was not possible within this study, so allocating publically financed infrastructure costs to specific generation technologies has not been undertaken. It was acknowledged that historical subsidies via grid investment could still exist for older power plants and possibly affect the market, but no quantification has been possible.

Limited liability of nuclear accidents

In most EU countries the liability of power utilities for nuclear accidents is limited (limited liability to their capital, as table A2-9 shows). In the case of other technologies this is also true, however, in the case of serious nuclear accidents the costs are higher by several magnitudes. Therefore costs of accidents are estimated as external costs and not internalised by interventions.

Accounting of stranded costs as subsidy

According to the comments of most of the stakeholders stranded costs should only be taken into account as subsidy if they have been paid by the state. This comment has been accepted in the methodology.

Looking into subsidies in the future

Some stakeholders proposed to also take into account those subsidies, for which the decision of granting has already been made, though they will be granted in the forthcoming years or decades (e.g.: in the case of renewable subsidies feed-in tariffs and premiums are given for a predefined timeframe). The most recent period of the current report is 2012 and the methodology takes into account only those subsidies, which are actually paid and affecting current market prices, not prices in the future. Therefore disbursements in the future have not been taken into account. However, some decommissioning subsidies, stemming from extremely low decommissioning costs in some countries compared to other Member States, may invoke actual subsidy disbursements in the future, as it is described in Chapter 2.9.6 of Annex of the report.

External costs

Fuel and metal depletion costs

Market prices should normally reflect all information currently available on the market, which impact both supply and demand. Some stakeholders say that this is also true for the depletion of resources; market prices incorporate the anticipation of the scarcity of a given resource in the future. However, the broad literature on the matter suggests this is not the case, that current market prices cannot fully reflect depletion of resources in the future. It is enough to think on the several-fold increase in crude oil prices during the past fifteen years, which was mainly due to increase in demand on the energy markets, while proven oil reserves grew significantly during the same period, implying that fear of scarcity had not much to do with the price increase. Following stakeholder comments, in the case of oil, natural gas, coal and uranium *different* assumptions have been made on production costs and the intensity of resource depletion in the future. Sensitivity analyses have been carried out on both production costs and the intensity of depletion in the report. In addition, in the presentation of external costs fuel depletion has been put on the top of other externalities on the charts, enabling the readers to see this item separately.

A similar logic applies to metal depletion costs, the contractor presents its model in which this item is also accounted, and current metal market prices do not reflect future scarcities in this interpretation.

Calculation of climate change costs

Given the very low current market prices of emission allowances in the Emission Trading System (ETS - 5-8 €/tCO_2e during the last two years), many stakeholders believe that the central assumption made by the contractor - 50 €/t CO_2e for damage cost of climate change – does not reflect the reality. In their view sources from other models would result in lower values and this high central value does not provide for a technology neutral approach of external costs from climate change.

The rationale behind the choice of was the result of a thorough literature review €50/t CO_2e is a reasonable central estimate of the cost of climate change; and this is not strongly related to the current market price of carbon.

All known models assume climate costs of higher magnitude than the current carbon price level (in 2012 6.67 €/t CO_2e on average, which was deducted from the first central carbon cost assumption, taking into account of the internalisation impact). The contractor has quoted several sources in the final report (See Chapter 3.1.6 of the Annex), ranging practically from 20 to 85 €/t CO_2e. The central value of 50 €/t CO_2e has been taken into account and a sensitivity analysis for low and high values (30€/t CO_2e and 100€/t CO_2e) has been carried out, showing the carbon damage costs are quite sensitive to the choice of input value. It seems that a satisfactory choice for all stakeholders could not be achieved.

The reason behind the choice of external costs taken into account

There are eighteen different types of externalities taken into account by the applied model of the contractor (based on Extern-E/NEEDS), grouped in three categories: human health damages, ecosystem and biodiversity related external costs and resource depletion costs. During the preparation process of the report the input values for the model have been updated, following comments from the stakeholders. In the case of each generation technology unit external costs (€/MWh) are assigned to each externality in the model.

The model is based on life-cycle assessments, meaning that it takes into account not only the power or heat generation phase of the energy sector, but upstream or waste management areas as well. External costs are calculated individually for each EU member state, however, some external costs can be assigned to the upstream phase of the energy sector (e.g.: mining, fuel processing), which are related to third countries outside the EU. In this case no geographical distinction is made, as it is not possible due to lack of appropriate data, and the same costs are assigned to each country.

External benefits, the impact of energy on human life

Energy has a profound impact on human life and the economy as a whole; it is indispensable for most of the human activities. Therefore it has a beneficial impact, which at least in the view of some stakeholders, should also be taken into account when its external costs are identified.

In fact, the goal of the preparation of the energy costs and subsidies report was to look at how generation costs and external costs of energy are impacted by subsidies, and how government interventions in the energy sector distort the market. The benefits of energy are not external, as they are included in the market price; energy needed for all activities is purchased on the market.

System costs (grid connection, back-up, balancing costs) and external costs

Different energy sources have grid connection costs and costs of back-up capacities. Some of the stakeholders believe that these costs are higher for specific technologies (especially wind and solar power) and should have been numerically expressed in the study and added to external costs of the related generation technologies.

All production - including wind, solar, nuclear, hydro – face grid connection costs and can impose back up costs. Historically, all technologies have been subsidised through socialised network charges covering grid and connection costs. They are not external costs, though there are cross subsidies still. Backup costs are reflected in balancing market prices and penalty regimes. Data in both of these areas seems weak and would require further exploration.

In the case of the allocation of system costs, despite the consultants' discussions with TSOs and regulators, it appears that for both historical and current investments, it is difficult to allocate costs to specific technologies or producers (or TSOs are reluctant to allocate through their network charges). The stakeholder workshop included an interesting discussion where the role of network charges emerged as important – the question of shallow/deep charging (which reflects the degree of socialised costs/cross subsidy). This is a sensitive topic where there is widely differing national practice

In the case of the costs of back up capacity – another dimension of "system costs", part of the answer is that in functioning intra-day and balancing markets, peak pricing should finance back up capacity, although we need to take into account capacity markets as well. As the share of renewable sources will grow further in the future, the importance of back-up capacities might grow, however, the current study does not focus on future market; we looked at current market conditions and the historical dimension. In Box 2-4 of the main report alternative data sources are presented, noting that currently such costs attributable to variable energy (wind and solar) are not significant, but that such costs would become significant when the power shares of such technologies themselves become significant, by 2030 and 2050.

Water depletion costs (cooling water)

As most of the water used for power generation processes is returned to the environment, it is crucial to differentiate between net and gross water consumption. During several steps of drafting the report this approach has been improved, on the basis of stakeholder feedback.

An initial overestimation of water depletion in this dataset was corrected. However, some countries would have preferred to have separate water depletion costs, depending on whether seawater or sweet water is used for cooling. Due to the lack of robust data, only a general figure has been applied for all of the EU Member States having operating nuclear reactors.

Water flowing back to the river or ocean was added to the datasets. Consumption data has been aligned to an existing study[2], on water consumption of nuclear and fossil fuel plants consumption. In the sub-chapter of uncertainties of the final document it is mentioned that the results on water depletion should be taken into account with caution.

External costs of accidents

All forms of energy production have an associated risk of an accident, for example there have been high profile coal mining accidents (mostly outside the EU in recent years) and accidents during oil and gas extraction. In the case of nuclear, the cost and consequences of any accident has the potential to be very much higher than for other energy sources.

Estimating the actual costs associated with a nuclear accident is not an easy task, because there is a lack of data and examples (not many accidents have occurred). In addition, there are indirect external costs, such as damage to a countries reputation and longer term costs (increased morbidity rates related to nuclear accidents). The literature has estimated the external costs of accidents, expressed in euro per electricity production, often resulting in a euro per MWh range, generally depending on inter alia type of accident, risk assumptions, frequency and location of the site.

The study reports that the external cost due to a nuclear accident ranges from EUR 0.5 to 4 per MWh. In earlier versions of the report this range was higher; following a thorough literature review it has been amended. The current range has been added to the external costs of nuclear power as presented in Figure 3-5 in the main report. The range we use is comparable with the D'haeseleer study[3], saying that the external cost of nuclear accidents can be estimated in the order of 0.3-3 € per MWh.

[2] Commissioned by Directorate General for Environment of the European Commission

[3] http://ec.europa.eu/energy/nuclear/forum/doc/final_report_dhaeseleer/synthesis_economics_nuclear_20131127-0.pdf

Costs of generation

The reason why the levelised costs concept has been chosen to calculate generation costs for electricity and heat

To quantify the true 'cost' of energy is an extremely complex matter, as it depends on the age and type of plant operating in a particular country as well as physical and market connections. To do an exercise taking into account all generation technologies, power plants of different ages across the twenty-eight Member States of the EU would have required a large scale data collection, which, in the lack of time and resources, was not a feasible solution.

Recurring to an alternative method, levelised costs (LCs) are commonly used for comparing technologies. Some stakeholders criticised this choice of method, recalling that these values for new projects give much higher values than current market electricity prices, therefore LCs cannot be used as a yardstick for investment decisions. Indeed, the LC concept serves purely for theoretical comparisons across different technologies, countries or over time.

In this study, levelised costs are used to set the size of the interventions and external costs in the context of a measure of the cost of energy, if the system was being newly developed, without government intervention. These estimates are based on new energy plants. These hypothetical plants do not determine either current market revenues or consumer prices.

The cost calculations cover capital expenditure (also including decommissioning and waste management), operational expenditure, fuel costs and revenues from the sales of by-products (e.g.: in the case of CHP).

The choice for power plants, generation technologies and the reason why plant refurbishments have not been taken into account

The contractor has endeavoured to identify the most typical plant types, being representative for each generation technology for most of the EU member states. Table 2-2 of the main report contains the main assumptions for these reference technologies. In the case of nuclear power Generation III power plants were supposed to be chosen, however, due to the limited number of construction projects, finally the Generation II technology has been chosen as reference.

In the case of some technologies taking into account plant refurbishments, assuring a cheaper solution than new constructions, being reflected in levelised costs, could have been taken into account. However, as a technology neutral approach was followed during the preparation of the whole report, and data were not available for most of the generation technologies (notably for coal), the idea of calculating refurbishment costs has been abandoned.

Assumptions behind the calculation of the WACC rates for levelised costs

In the report Weighted Average Cost of Capital (WACC) rates, presented in Chapter 4.2.3 of the Annex, are post-tax, nominal discount rates.

For the debt part, 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. 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 a fixed value for the WACC is assumed, which reflects consumer behaviour in most European countries.

The equity side of the WACC varies over countries and technologies. The equity part of the WACC rates are built up by adding country-specific market risk premium and technology-specific premiums. 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 hand.

The method chosen by the contractor for calculation the WACC rates was drawn from the IEA (RETD) rather than that of the European Commission (which, however, also uses an average WACC differences at

EU level. WACC rates for household energy generation technologies (rooftop solar panels, boilers, etc.) are set to be lower than for industrial technologies, based on two assumptions. First, 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). Second, levels of risks are typically lower (e.g.: a household boiler vs. an offshore wind park).

Data sources for input factors of levelised cost calculations, namely fuel costs, full load hours, etc.

For full load hours (both technical and realised) principally Eurostat data has been used, in the case of photovoltaics a European Commission database, for wind power it was the Norsewind Atlas (see in Chapter 4.2.2 in the Annex). Using one common source for full load hours aimed at assuring comparability at EU level. In the case of fuel costs member state level data was taken from Eurostat or other international databases, such as that of IEA. Other elements of the LC calculation are coming from local data collections in the twenty eight member states.

In the case of lignite based power generation LCs could not be calculated as power plants are normally set up near to lignite mines and in many cases lignite input costs for power generation are not available (the lignite source and the power plant are operated by the same company and the lignite does not appear in commercial trade). In the case of renewables, coming first in the merit order of electricity generation, it is ensured that there are no differences in LCOEs between technical and realised full load hours.

Why fuel costs are kept constant throughout the lifetime of the power plants?

Some stakeholders criticised the way LCs are calculated, as input fuel prices are kept constant over time, while there are model assumptions according to which most of non-renewable fuel prices will increase over the forthcoming decades. If fuel prices are kept constant, this will favour thermal (fuel based) technologies, showing lower LCs. However the study avoided the difficulty of simulating historical fuel price changes and assumes average prices.

Are network costs included in Levelised costs?

Grid infrastructure capital expenditure, operation and maintenance costs are not included in levelised costs; they are presented in a separate Chapter (4.4 in the Annex). These costs are calculated for electricity and gas transmission networks, in the case of some countries distribution networks are also included as it was not possible to separate them out. In some countries, either for electricity or for gas there are data gaps for grid costs.

In the case of offshore wind grid connection costs are included in the levelised costs of electricity calculation, as this is a significant item within generation costs and without connection offshore wind parks cannot go online.

Other comments

The contractor has performed an extensive data collection, modelling and calculation exercise, based on a thorough literature review, data collection in all EU Member States and in the case of external costs relying on their own model.

In a number of areas (e.g.: historic subsidies, climate change costs, fuel depletion costs) the contractor had to rely on assumptions, and as sensitivity analyses show, in some cases a significant level of uncertainty has been assigned to the estimations. Assumptions and uncertainties are summarised in Chapter 3.4 of the Annex.

Although the final report on energy costs and subsidies in the EU is so far the most comprehensive document, aiming at putting together and comparing generation costs, external costs and subsidies in the energy sector, which could help in understanding how government interventions impact the internal energy market, there are still a number of data gaps (e.g.: system costs of generation technologies, historic subsidies for infrastructure, etc.), which could only be filled if further investigations are carried out to find better data sources.