Projected Costs of Generating Electricity

2010 Edition

OECD

International Energy Agency

NEA Nuclear Energy Agency

Projected Costs of Generating Electricity

This joint report by the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA) is the seventh in a series of studies on electricity generating costs. It presents the latest data available for a wide variety of fuels and technologies, including coal and gas (with and without carbon capture), nuclear, hydro, onshore and offshore wind, biomass, solar, wave and tidal as well as combined heat and power (CHP). It provides levelised costs of electricity (LCOE) per MWh for almost 200 plants, based on data covering 21 countries (including four major non-OECD countries), and several industrial companies and organisations. For the first time, the report contains an extensive sensitivity analysis of the impact of variations in key parameters such as discount rates, fuel prices and carbon costs on LCOE. Additional issues affecting power generation choices are also examined.

The study shows that the cost competitiveness of electricity generating technologies depends on a number of factors which may vary nationally and regionally. Readers will find full details and analyses, supported by over 130 figures and tables, in this report which is expected to constitute a valuable tool for decision makers and researchers concerned with energy policies and climate change.

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2010 Edition

INTERNATIONAL ENERGY AGENCY
NUCLEAR ENERGY AGENCY
ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its mandate is two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply and to advise member countries on sound energy policy.

The IEA carries out a comprehensive programme of energy co-operation among 28 advanced economies, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports.

The Agency aims to:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries are: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea (Republic of), Luxembourg, the Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The European Commission also participates in the work of the IEA.

NUCLEAR ENERGY AGENCY

The OECD Nuclear Energy Agency (NEA) was established on 1st February 1958 under the name of the OEEC European Nuclear Energy Agency. It received its present designation on 20th April 1972, when Japan became its first non-European full member. NEA membership today consists of 28 OECD member countries: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, Norway, Portugal, Republic of Korea, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The Commission of the European Communities also takes part in the work of the Agency.

The mission of the NEA is:

- to assist its member countries in maintaining and further developing, through international co-operation, the scientific, technological and legal bases required for a safe, environmentally friendly and economical use of nuclear energy for peaceful purposes, as well as
- to provide authoritative assessments and to forge common understandings on key issues, as input to government decisions on nuclear energy policy and to broader OECD policy analyses in areas such as energy and sustainable development.

Specific areas of competence of the NEA include safety and regulation of nuclear activities, radioactive waste management, radiological protection, nuclear science, economic and technical analyses of the nuclear fuel cycle, nuclear law and liability, and public information.

The NEA Data Bank provides nuclear data and computer program services for participating countries. In these and related tasks, the NEA works in close collaboration with the International Atomic Energy Agency in Vienna, with which it has a Co-operation Agreement, as well as with other international organisations in the nuclear field.

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

The OECD is a unique forum where the governments of 30 democracies work together to address the economic, social and environmental challenges of globalisation. The OECD is also at the forefront of efforts to understand and to help governments respond to new developments and concerns, such as corporate governance, the information economy and the challenges of an ageing population. The Organisation provides a setting where governments can compare policy experiences, seek answers to common problems, identify good practice and work to co-ordinate domestic and international policies.

The OECD member countries are: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The Commission of the European Communities takes part in the work of the OECD.

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Foreword

This joint report by the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA) is the seventh in a series of studies, started in 1983, on the projected costs of electricity generation. Despite increased concerns about the confidentiality of commercially relevant cost data, the 2010 edition – thanks to the co-operation of member countries, non-member countries, industry and academia – includes a larger number of technologies and countries than ever before.

The study contains data on electricity generating costs for almost 200 power plants in 17 OECD member countries and 4 non-OECD countries. It was conducted under the supervision of the Ad hoc Expert Group on Electricity Generating Costs which was composed of representatives of the participating OECD member countries, experts from the industry and academia as well as from the European Commission and the International Atomic Energy Agency (IAEA). Experts from Brazil, India and Russia also participated.

In Part I, the study presents the projected costs of generating electricity calculated according to common methodological rules on the basis of the data provided by participating countries and organisations. Data were received for a wide variety of fuels and technologies, including coal, gas, nuclear, hydro, onshore and offshore wind, biomass, solar, wave and tidal. Cost estimates were also provided for combined heat and power (CHP) plants, as well as for coal plants that include carbon capture. As in previous studies of the same series, all costs and benefits were discounted or capitalised to the date of commissioning in order to calculate the levelised costs of electricity (LCOE) per MWh, based on plant operating lifetime data.

The LCOE provided in Part I depend heavily, of course, on the underlying assumptions. While reasonable and vetted by experts, these assumptions can never cover all cases. Part II therefore provides a number of sensitivity analyses that show the relative impact on LCOE of changes in key underlying variables such as discount rates, fuel, carbon or construction costs, or even load factors and lifetimes of plants. This provides the reader with a more complete picture.

In addition, Part II also contains a number of discussions on "boundary issues" that do not necessarily enter into the calculation of LCOE but have an impact on decision making in the electricity sector. They include the factors affecting the cost of capital, the outlook for carbon capture and storage, the working of electricity markets and the systemic effects of intermittent renewable energies. A concluding chapter provides information on other studies of electricity generating costs. Two annexes contain information on the data from non-OECD countries and a list of abbreviations. It is the hope of the authors that the final product will constitute a valuable tool for policy makers, market players and researchers concerned with energy and climate change policies.

This study is published under the responsibility of the OECD Secretary-General and the IEA Executive Director. It reflects the collective views of the participating experts, though not necessarily those of their parent organisations or governments.

Acknowledgements

The lead authors and coordinators of the study were Ms. María Sicilia Salvadores, Senior Electricity Markets Expert, IEA, and Professor Jan Horst Keppler, Principal Economist, NEA. They would like to acknowledge the essential contribution of the EGC Expert Group, which assisted in the sourcing of data, provided advice on methodological issues and reviewed successive drafts of the study. The Group was expertly chaired by Professor William D'haeseleer from Belgium. Dr. Koji Nagano (Japan), Dr. John Paffenbarger (United States) and Professor Alfred Voss (Germany) assiduously served the Group as Vice-Chairmen and members of the Bureau. Mr. Ian Cronshaw (IEA), Dr. Thierry Dujardin (NEA) and Mr. Didier Houssin (IEA) provided managerial oversight. The study benefitted greatly from the work of Ms. Alena Pukhova, NEA Consultant.

Mr. Hugo Chandler, IEA ("System Integration Aspects of Variable Renewable Power Generation"), Mr. François Nguyen, IEA ("Levelised Costs and the Working of Actual Power Markets") and Dr. Uwe Remme, IEA ("Carbon Capture and Storage") were the lead authors of specific chapters in Part II of this study. The "Synthesis Report on Other Studies of the Levelised Cost of Electricity" was contributed by Mr. Claudio Marcantonini and Professor John E. Parsons, both from the Massachusetts Institute of Technology (MIT). Mr. Alex Zhang, IEA intern, provided research assistance for cost data in China. Ms. Mari Vie Maeland (IEA), Mr. Wouter van der Goot (IEA) and Ms. Esther Ha (NEA) all assisted with the important task of managing large amounts of cost data. Ms. Hélène Déry (NEA) provided consistent and comprehensive administrative support.

List of participating members of the Expert Group

Data for this study was provided through the Expert Group, except in the case of China for which the Secretariat collected publicly available data from a variety of Chinese sources. The joint Secretariat is happy to refer any enquiries about data to the respective experts. Please contact for this purpose María Sicilia Salvadores (maria.sicilia@iea.org) or Jan Horst Keppler (jan-horst.keppler@oecd.org).

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Executive summary

Projected Costs of Generating Electricity – 2010 Edition presents the main results of the work carried out in 2009 for calculating the costs of generating baseload electricity from nuclear and fossil fuel thermal power stations as well as the costs of generating electricity from a wide range of renewable technologies, some of them with variable or intermittent production. All of the included technologies are expected to be commissioned by 2015. The core of the study consists of individual country data on electricity generating costs. However, the study also includes for the first time extensive sensitivity analyses for key cost parameters, since one of the objectives is to provide reliable information on key factors affecting the economics of electricity generation using a range of technologies. This new report in the series continues the now traditional representation of baseload generating costs made in order to compare the various types of generating plants within each of the countries represented and also to provide a basis for comparing generating costs between different countries for similar types of plant. The report can serve as a resource for policy makers, researchers and industry professionals seeking to better understand the power generation costs of different technologies.

The study focuses on the expected plant-level costs of baseload electricity generation by power plants that could be commissioned by 2015. It also includes the generating costs of a wide range of renewable energy sources, some of which have variable output. In addition, the report covers projected costs related to advanced power plants of innovative designs, namely commercial plants equipped with carbon capture, which might reach the level of commercial availability and be commissioned by 2020.

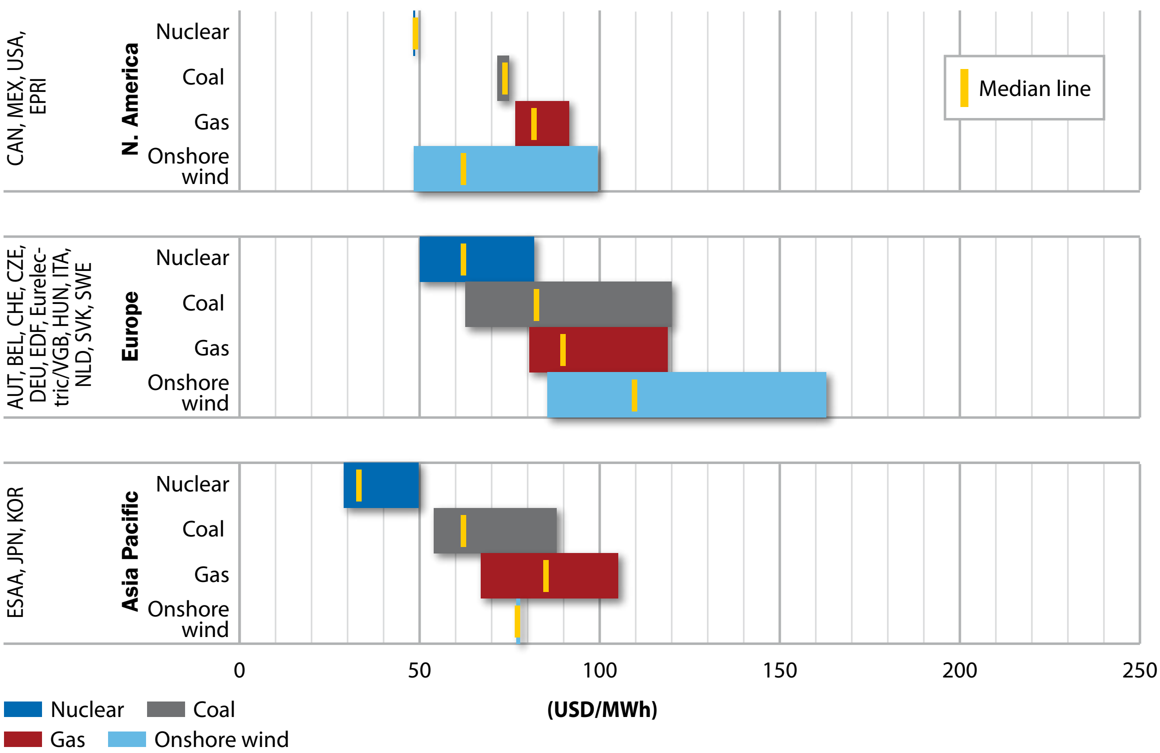
The study was carried out with the guidance and support of an ad hoc Expert Group of officially appointed national experts, industry experts and academics. Cost data provided by the experts were compiled and used by the joint IEA/NEA Secretariat to calculate the levelised costs of electricity (LCOE) for baseload power generation.

The calculations are based on the simple levelised average (unit) lifetime cost approach adopted in previous studies, using the discounted cash flow (DCF) method. The calculations use generic assumptions for the main technical and economic parameters as agreed upon by the ad hoc Expert Group. The most important assumptions concern the real discount rates, 5% and 10%, also keeping with tradition, fuel prices and, for the first time, a carbon price of USD 30 per tonne of CO_2.[1]

1. See Chapter 2 on "Methodology, conventions and key assumptions" for further details on questions of methodology and Chapter 7 on "Financing issues" for a discussion of discount rates. It needs to be kept in mind that the LCOE methodology deals with financial costs only and does not include any social or external costs of electricity production.

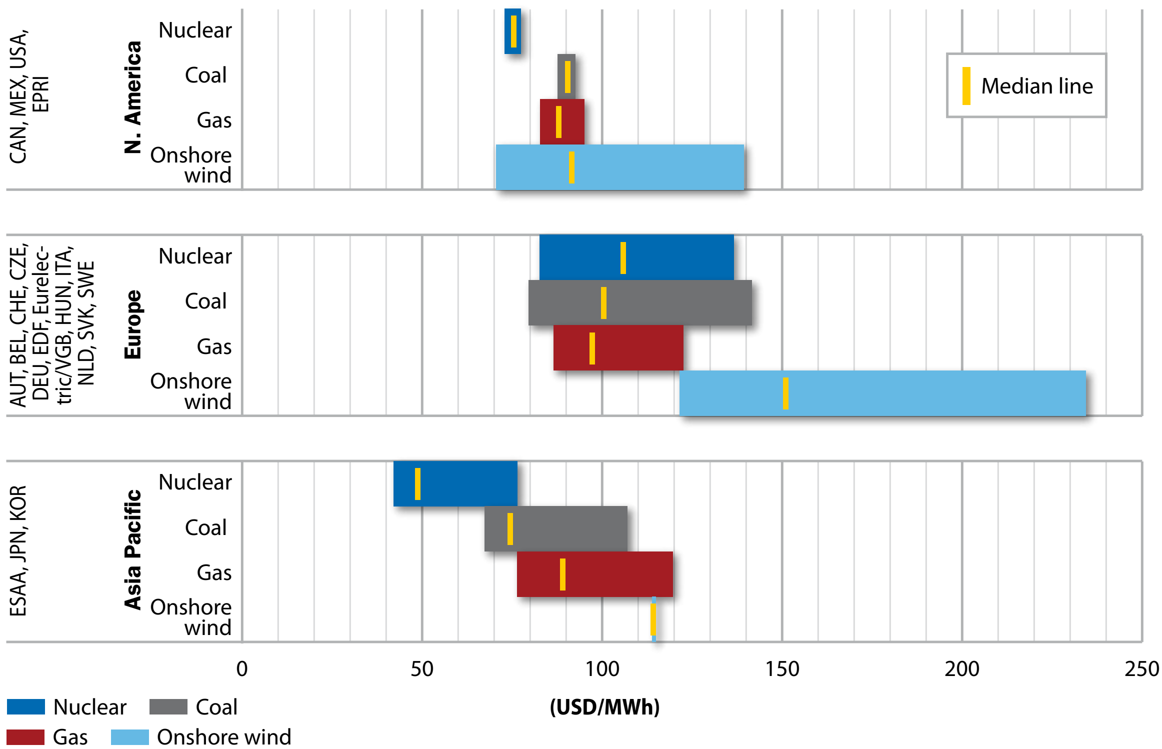
The study reaches two important conclusions (see Figures ES.1 and ES.2 below). First, in the low discount rate case, more capital-intensive, low-carbon technologies such as nuclear energy are the most competitive solution compared with coal-fired plants without carbon capture and natural gas-fired combined cycle plants for baseload generation. Based on the data available for this study, where coal is low cost (such as in Australia or certain regions of the United States), both coal plants with and without carbon capture [but not transport or storage, referred to as CC(S)] are also globally competitive in the low discount rate case. It should be emphasized that these results incorporate a carbon price of USD 30 per tonne of CO_2, and that there are great uncertainties concerning the cost of carbon capture, which has not yet been deployed on an industrial scale.

Figure ES.1: Regional ranges of LCOE for nuclear, coal, gas and onshore wind power plants
(at 5% discount rate)



Second, in the high discount rate case, coal without carbon capture equipment, followed by coal with carbon capture equipment, and gas-fired combined cycle turbines (CCGTs), are the cheapest sources of electricity. In the high discount rate case, coal without CC(S) is always cheaper than coal with CC(S), even in low-cost coal regions, at a carbon price of USD 30 per tonne. The results highlight the paramount importance of discount rates and, to a lesser extent, carbon and fuel prices when comparing different technologies. The study thus includes extensive sensitivity analyses to test the relative impact of variations in key cost parameters (such as discount rates, construction costs, fuel and carbon prices, load factors, lifetimes and lead times for construction) on the economics of different generating technologies individually considered.

Figure ES.2: Regional ranges of LCOE for nuclear, coal, gas and onshore wind power plants
(at 10% discount rate)



Features of the method of calculation

The study includes 21 countries and gathered cost data for 190 power plants. Data was provided for 111 plants by the participants in the Expert Group representing 16 OECD member countries (Austria, Belgium, Canada, Czech Republic, France, Germany, Hungary, Italy, Japan, Korea, Mexico, Netherlands, Slovak Republic, Sweden, Switzerland and United States), for 20 plants by 3 non-member countries (Brazil, Russia and South Africa) and for 39 plants by industry participants [ESAA (Australia), EDF (France), Eurelectric (European Union) and EPRI (United States)]. In addition, the Secretariat also collected data for 20 plants under construction in China using both publicly available and official Chinese data sources.

The total sample comprises 34 coal-fired power plants without carbon capture, 14 coal-fired power plants with carbon capture [referred to in the study as coal with CC(S)], 27 gas-fired plants, 20 nuclear plants, 18 onshore wind power plants, 8 offshore wind plants, 14 hydropower plants, 17 solar photovoltaic plants, 20 combined heat and power (CHP) plants using various fuels and 18 plants based on other fuels or technologies. The data provided for the study highlight the increasing interest of participating countries in low-carbon technologies for electricity generation, including nuclear, wind and solar power, CHP plants as well as first commercial plants equipped with carbon capture, all key technologies for decarbonising the power sector.

The electricity generation costs calculated are plant-level (busbar) costs, at the station, and do not include transmission and distribution costs. Neither does the study include other systemic effects such as the costs incurred for providing back-up for variable or intermittent (non-dispatchable) renewable energies. For the calculation of the costs of coal-fired power generation with carbon capture, only the costs of capture net of transmission and storage have been taken into account. Finally, the cost estimates do not include any external costs associated either with residual emissions other than CO_2 emissions or impacts on the security of supply.

A number of key observations can be highlighted from the sample of plants considered in this study. A first issue is the wide dispersion of data. The results vary widely from country to country; even within the same region there are significant variations in the cost for the same technologies. While some of this spread of data reflects the timing of estimates (costs rose rapidly over the last four years, before falling late in 2008 and 2009), a key conclusion is that country-specific circumstances determine the LCOE. It is clearly impossible to make any generalisation on costs above the regional level; but also within regions (OECD Europe, OECD Asia), and even within large countries (Australia, United States, China or Russia), there are large cost differences depending on local cost conditions (e.g. access to fossil fuels, availability of renewable resources, different market regulations, etc.). These differences highlight the need to look at the country or even sub-country level.[2]

A second issue relates to the quality of data itself. High-quality data is needed to produce reliable figures. However, the widespread privatisation of utilities and the liberalisation of power markets in most OECD countries have reduced access to often commercially sensitive data on production costs. Data used in this study is based on a mix of current experience, published studies or industry surveys. The final cost figures are subject to uncertainty due to the following elements:

- Future fuel and CO_2 prices: it is important to note that for the first time a price of carbon for all OECD countries is internalised and included in LCOE calculations. Policies to reduce greenhouse gas emissions have reached a level of maturity such that members of the Expert Group decided that a carbon price of 30 USD per tonne of CO_2 was now the most realistic assumption for plants being commissioned in 2015. Nevertheless, the group underlines the uncertainties connected to this assumption.
- Present and future financing costs.
- Construction costs.
- Costs for decommissioning and storage, which particularly affect nuclear energy, still remain uncertain due to the relatively small experience base, noting that the DCF methodology employed in the study means that decommissioning costs become negligible for nuclear at any realistic discount rate.
- In an indirect manner, the results of the study also depend on future electricity prices since the LCOE methodology presupposes stable electricity prices that fully cover costs over the life of a power plant. A different electricity price assumption would yield different results.

The current edition of *Projected Costs of Generating Electricity* has been produced in a period of unprecedented uncertainty given the current economic and policy context, characterised on the one hand by the growing momentum of climate change policies as well as uncertainty about the timing of the impact of policy measures and, on the other hand, by the dramatic changes in economic conditions affecting both energy demand and supply.

2. In particular, the cost for renewable energy technologies shows important variations from country to country and, within each country, from location to location. In addition, some of the largest current markets for renewable energy are not represented in the study.

In addition to the uncertainties described above, there are also other factors which cannot be adequately incorporated into a cross-country analysis but need to be acknowledged, and are therefore dealt with in the study in a qualitative manner in dedicated boundary chapters:

- integrating variable and intermittent renewable energies in most existing electricity systems;
- current cost of capital for energy projects and differences in tax treatment;
- issues in connection with the behaviour of energy markets (demand and price risk);
- cost of CC(S), a technology that can be key for the decarbonisation of the power sector, yet is still in the development stage.

Increased uncertainty drives up costs through higher required returns on investment/discount rates, and this applies to *all* electricity generating technologies. However, higher discount rates penalise more heavily capital-intensive, low-carbon technologies such as nuclear, renewables or coal with CC(S) due to their high upfront investment costs, and comparatively favour fossil-fuel technologies with higher operating costs but relatively lower investment costs, especially gas CCGT. For renewable technologies, site-specific load factors can also be decisive. Overall, however, access to financing and the stability of the environmental policy frameworks to be developed in the coming years will be crucial in determining the outcome of the successful decarbonisation of the power sector.

Main results

With all the caveats inherent to the EGC methodology, *Projected Costs of Generating Electricity* nevertheless enables the identification of a number of tendencies that will shape the electricity sector in the years to come. The most important among them is the fact that nuclear, coal, gas and, where local conditions are favourable, hydro and wind, are now fairly competitive generation technologies for baseload power generation.[3] Their precise cost competitiveness depends more than anything on the local characteristics of each particular market and their associated cost of financing, as well as CO_2 and fossil fuel prices.[4] As mentioned earlier, the lower the cost of financing, the better the performance of capital-intensive, low-carbon technologies such as nuclear, wind or CC(S); at higher rates, coal without CC(S) and gas will be more competitive. There is no technology that has a clear overall advantage globally or even regionally. Each one of these technologies has potentially decisive strengths and weaknesses that are not always reflected in the LCOE figures provided in the study.

Nuclear's strength is its capability to deliver significant amounts of very low carbon baseload electricity at costs stable over time; it has to manage, however, high amounts of capital at risk and its long lead times for construction. Permanent disposal of radioactive waste, maintaining overall safety, and evolving questions concerning nuclear security and proliferation remain issues that need to be solved for nuclear energy.

3. The variable nature of wind power, in contrast to conventional, dispatchable technologies, requires flexible reserves to be on hand for when the resource is not available. Thus, the wind cost is higher at the level of the system than at the level of the plant, although our analysis of integration studies (see Chapter 7) suggests that this additional cost is not prohibitive. System costs are likely to be lower in larger markets, with a geographical spread of plants, and when wind is part of a complementary portfolio of other generation technologies.

4. Other renewable energies are for the time being outside this range, although significant cost reductions are expected with larger deployment, in particular for solar PV as intermediate load.

Coal's strength is its economic competitiveness in the absence of carbon pricing and neglecting other environmental costs. This applies in particular where coal is cheap and can be used for generating electricity close to the mine, such as in the western United States, Australia, South Africa, India and China. However, this advantage is markedly reduced where significant transport or transaction costs apply, or where carbon costs are included. The high probability of more generalised carbon pricing and more stringent local environmental norms thus drastically reduce the initial cost advantage.

Carbon capture [CC(S)] has not yet been demonstrated on a commercial scale for fossil-fuelled plant. The costs provided in the study refer to carbon capture at plant level [CC(S)]; an unproven rule of thumb says that transport and storage might add another USD 10-15 per MWh. Until a realistic number of demonstration plants have been operated for worthwhile time frames, total CC(S) costs will remain uncertain.

The great advantage of *gas-fired power* generation is its flexibility, its ability to set the price in competitive electricity markets, hedging financial risk for its operators and its lower CO_2 profile; on the other hand, when used for baseload power production it has comparatively high costs given the gas price assumptions (except at high discount rates) and is subject to security of supply concerns in some regions. Progress in the extraction of lower-cost shale gas has eased the supply and demand balance and therefore improved the competitive outlook for natural gas in North America, where prices are around half those based on oil-indexation in Continental Europe or the OECD Asia-Pacific region.

For the first time, *onshore wind* is included among the potentially competitive electricity generation sources in this edition of *Projected Costs of Generating Electricity*. On the basis of the dynamics generated by strong government support, onshore wind is currently closing its still existing but diminishing competitiveness gap. Its weakness is its variability and unpredictability, which can make system costs higher than plant costs, although these can be addressed through geographic diversity and an appropriate mix with other technologies. According to the data available for this study, offshore wind is currently not competitive with conventional thermal or nuclear baseload generation. Many renewable technologies, however, are immature, although their capital costs can be expected to decline over the next decade. Renewables, like nuclear, also benefit from stable variable costs, once built.

If *Projected Costs of Generating Electricity* is any indication, the future is likely to see healthy competition between these different technologies, competition that will be decided according to national preferences and local comparative advantages. At the same time, the margins are so small that no country will be able to insulate its choices from the competitive pressures emanating from alternative technology options. The choices available and the pressure on operators and technology providers to offer attractive solutions have never been greater. In the medium term, investing in power markets will be fraught with uncertainty.

Coal-fired generating technologies

Most coal-fired power plants in OECD countries have overnight investment costs ranging between 900 and 2 800 USD/kWe for plants without carbon capture.[5] Plants with carbon capture have overnight investment costs ranging from 3 223 to 6 268 USD/kWe. Coal plants with carbon capture are henceforth referred to as "coal plants with CC(S)" in order to indicate that their cost estimates do not include the costs for storage and transportation.

5. Overnight construction costs include owner's cost, EPC (engineering, procurement and construction) and contingency, but exclude interests during construction (IDC). Total investment costs include IDC, but exclude refurbishment or decommissioning.

Construction times are approximately four years for most plants. From the data provided by respondents, the prices of both black coal and brown coal vary significantly from country to country. Expressed in the same currency using official exchange rates, coal prices can vary by a factor of ten. The study assumed a black coal price of USD 90 per tonne except for large coal-producing countries that are partly shielded from world markets such as Australia, Mexico and the United States, where domestic prices were applied. For brown coal, domestic prices were applied in all cases.

With a carbon price of 30 USD/tonne, the most important cost driver for coal plants without CC(S) is the CO_2 cost in the low discount rate case. In the case of coal plants equipped with CC(S), the construction cost is the most important cost driver in the low discount rate case. In the high discount rate case, where total investment cost is more important, variations in the discount rate, closely followed by construction costs, are key determinants of total costs for both coal plants with and without CC(S).

At a 5% discount rate, levelised generation costs in OECD countries range between 54 USD/MWh (Australia) and 120 USD/MWh (Slovak Republic) for coal-fired power plants both with and without carbon capture. Generally, investment costs and fuel costs each represent around 28%, while operations and maintenance (O&M) costs account for some 9% and carbon costs around one-third of the total.

At a 10% discount rate, the levelised generation costs of coal-fired power plants in OECD countries range between 67 USD/MWh (Australia) and 142 USD/MWh (Slovak Republic) also for plants both with and without carbon capture. Investment costs represent around 42% of the total, fuel costs some 23%, O&M costs approximately 8% and carbon costs 27% of the total LCOE.

Gas-fired generating technologies

For the gas-fired power plants without carbon capture in the OECD countries considered in the study, the overnight construction costs in most cases range between 520 and 1 800 USD/kWe. In all countries considered, the investment costs of gas-fired plants are lower than those of coal-fired and nuclear power plants. Gas-fired power plants are built rapidly and, in most cases, expenditures are spread over two to three years. The O&M costs of gas-fired power plants are significantly lower than those of coal-fired or nuclear power plants in all countries which provided data for the two or three types of plants considered. The study assumed prices of USD 10.3/MMBtu in OECD Europe and USD 11.7/MMBtu in OECD Asia. National assumptions were assumed for large gas-producing countries such as Australia, Mexico and the United States.

At a 5% discount rate, the levelised costs of generating electricity from gas-fired power plants in OECD countries vary between 67 USD/MWh (Australia) and 105 USD/MWh (Italy). On average, investment cost represents only 12% of total levelised costs, while O&M costs account for 6% and carbon costs for 12%. Fuel costs instead represent 70% of the total levelised cost. Consequently, the assumptions on gas prices used in the study are the driving factors in the estimated levelised costs of gas-generated electricity.

At a 10% discount rate, levelised costs of gas-fired plants in OECD countries range between 76 USD/MWh (Australia) and 120 USD/MWh (Italy). The difference between costs at a 5% and a 10% discount rate is very limited due to their low overnight investment costs and short construction periods. Fuel cost remains the major contributor representing 67% of total levelised generation cost. Investment costs amount to 16%, while O&M and carbon costs contribute around 5% and 11% respectively to total LCOE.

Nuclear generating technologies

Cost figures for nuclear power plants vary widely reflecting the importance of national conditions and the lack of recent construction experience in many OECD countries. For the nuclear power plants in the study, the overnight construction costs vary between 1 600 and 5 900 USD/kWe with a median value of 4 100 USD/kWe. The study considered different Generation III technologies including the EPR, other advanced pressurised water reactor designs as well as advanced boiling water reactor designs.

At a 5% discount rate, the levelised costs of nuclear electricity generation in OECD countries range between 29 USD/MWh (Korea) and 82 USD/MWh (Hungary). Investment costs represent by far the largest share of total levelised costs, around 60% on average, while O&M costs represent around 24% and fuel cycle costs around 16%. These figures include costs for refurbishment, waste treatment and decommissioning after a 60-year lifetime.

At a 10% discount rate, the levelised costs of nuclear electricity generation in OECD countries are in the range of 42 USD/MWh (Korea) and 137 USD/MWh (Switzerland). The share of investment in total levelised generation cost is around 75% while the other cost elements, O&M costs and fuel cycle costs, represent 15% and 9% respectively. Again, these figures include costs for refurbishment, waste treatment and decommissioning after a 60-year lifetime.

Renewable generating technologies

For onshore wind power plants, the specific overnight construction costs are in the range of 1 900 to 3 700 USD/kWe. The expense schedules reported indicate a construction period between one to two years in the majority of cases. As with all other technologies, the costs calculated and presented in this report for wind power plants are plant-level costs. They therefore do not include specific costs associated with the integration of wind or other intermittent renewable energy sources into most existing electric systems and, in particular, the need for backup power capacities to compensate for the variability and limited predictability of their production.

The levelised costs of electricity produced with onshore wind and solar PV technologies exhibit a very high sensitivity to the load factor variation, and to a lesser extent to the construction cost, at any discount rate. In contrast with nuclear and thermal plants with a generic load factor of 85%, plant-specific load factors were used for renewable energy sources. For variable renewable sources such as wind, the availability of the plant is in fact an important driving factor for the levelised cost of generating electricity. The reported load factors of wind power plants range between 21% and 41% for onshore plants, and between 34% and 43% for offshore plants except in one case.

At a 5% discount rate, levelised generation costs for onshore wind power plants in OECD countries considered in the study range between 48 USD/MWh (United States) and 163 USD/MWh (Switzerland), and from 101 USD/MWh (United States) to 188 USD/MWh (Belgium) for offshore wind. The share of investment costs is 77% for onshore wind turbines and 73% for offshore wind turbines.

At a 10% discount rate, the levelised costs of wind-generated electricity in OECD countries range between 70 USD/MWh (United States) and more than 234 USD/MWh (Switzerland). For offshore wind turbines the costs range from 146 USD/MWh (United States) to 261 USD/MWh (Belgium). The share of investment costs is 87% for onshore wind turbines and 80% for offshore wind turbines. For the latter, the difficult conditions of the marine environment imply a higher share of the costs for operations and maintenance.

For solar photovoltaic plants, the load factors reported vary from 10% to 25%. At the higher load factor, the levelised costs of solar-generated electricity are reaching around 215 USD/MWh at a 5% discount rate and 333 USD/MWh at a 10% discount rate. With the lower load factors, the levelised costs of solar-generated electricity are around 600 USD/MWh.

The two reported solar thermal plants have a load factor of 32% (Eurelectric) and 24% (US Department of Energy). The levelised costs range from 136 USD/MWh to 243 USD/MWh, for 5% and 10% discount rates respectively.

The current study also contains limited data on the cost of hydroelectric power generation. Depending on the plant size and specific site, hydro is competitive in some countries; however, costs vary so widely that no general conclusions can be drawn.

Conclusions

The levelised costs and the relative competitiveness of different power generation technologies in each country are highly sensitive to the discount rate and slightly less, but still significantly sensitive, to the projected prices for CO_2, natural gas and coal. For renewable energy technologies, country- and site-specific load factors also play an important role.

With the liberalisation of electricity markets, certain risks have become more transparent, so that project proponents must now bear and closely manage these risks (to the extent that they can no longer be transferred to consumers or taxpayers). This has implications for determining the required rate of return on generating investments. Access to financing and national support policies for individual technologies designed to reduce financing risks (such as feed-in tariffs, loan or price guarantees) are thus likely to play an important role in determining final power generation choices.

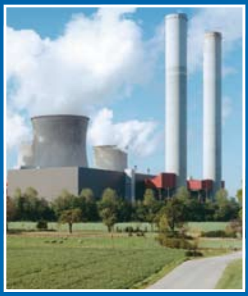
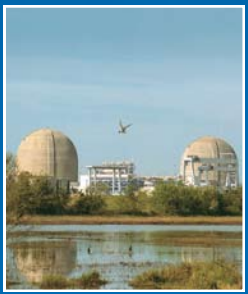
Environmental policy will also play an increasingly important role that is likely to significantly influence fossil fuel costs in the future and the relative competitiveness of various generation technologies. In addition, the markets for natural gas are undergoing substantial changes on many levels which make current projections for prices even more uncertain than usual. Also, coal markets are being influenced by new factors. Security of energy supply remains a concern for most OECD countries and may be reflected in government policies affecting generating investment in the future.

This study provides insights into the relative costs of generating technologies in the participating countries and reflects the limitations of the methodology and the generic assumptions employed. The limitations inherent in this approach are stressed in the report. In particular, the cost estimates presented do not represent the precise costs which would be calculated by potential investors for any specific project. Together with national energy policies favouring or discouraging specific technologies, the investors' concern about risk is one of the reasons explaining the difference between the study's findings and the market preference for gas-fired technologies. Different fuel price expectations may also affect investors' decisions in some markets.

Within this framework and various limitations, the study suggests that no single electricity generating technology can be expected to be the cheapest in all situations. The preferred generating technology will depend on a number of key parameters and the specific circumstances of each project. This edition of *Projected Costs of Generating Electricity* indicates that the investors' choice of a specific portfolio of power generation technologies will most likely depend on financing costs, fuel and carbon prices, as well as the specific energy policy context (security of supply, CO_2 emissions reductions, market framework).

Part 1

Methodology and data on levelised costs for generating electricity


Introduction and context

The joint IEA/NEA publication on *Projected Costs of Generating Electricity* is a regular exercise published about every five years. A large and active Expert Group accompanied the project through all its stages from data generation, over methodological treatment, to format and content of the final publication.

The result is a complete study on the levelised cost of electricity (LCOE) with an expanded coverage of both technologies and countries (see Table 1.1). For most OECD and non-OECD countries, the data has been received either through member countries' governments directly or by officially nominated experts to the ad hoc Expert Group.[1] Other contributions have been made by industrial companies or industry associations and are listed separately. The study tries to render its methodology transparent on each aspect of the life-cycle of a power plant, as well as to put the results into perspective through extensive sensitivity studies and a comparison with other studies. This study includes comprehensive data on generating costs in four large non-OECD countries (Brazil, China, Russia and South Africa), thus reflecting both the new realities of a changing world economy and the success of the intensive outreach activities of IEA and NEA. The 2010 edition of *Projected Costs of Generating Electricity* is designed to be an important tool for energy policy makers and the interested public in discussing power generation choices in the current energy and economic policy context.

And yet, no previous edition has faced the current degree of uncertainty. One indication for the uncertainties surrounding the estimates provided here are the large ranges even among OECD countries in the same region. There are at least five reasons for why this range of uncertainty today is larger than in previous times.

First, the widespread privatisation of utilities and the liberalisation of power markets in most OECD countries has reduced access to data on production costs. Private actors cite confidentiality and competitiveness concerns as reasons for not disclosing data on production costs.

Second, rarely have policy factors created more uncertainty for the cost of different power generation technologies than today. The imperative to reduce greenhouse gas emissions has led to new policy objectives which have an impact in power generation choices through explicit or implicit carbon pricing. *Projected Costs of Generating Electricity* has paid heed to this fact by assuming a carbon price of USD 30 per tonne of CO_2. This is a judgement call. So far, only the European Union has established a formal system for carbon pricing through the European Emission Trading System (EU ETS). However, in several other countries, such pricing schemes are being actively debated, and are implicitly affecting generation choices.

1. One of the exceptions is China, where data has been collected from a variety of public sources. See Annex I for further details.

Table 1.1: Summary overview of responses											
Country	**Nuclear**	**Coal**	**Coal w/CC(S)**	**Gas**	**Wind onshore**	**Wind offshore**	**Hydro**	**Solar PV**	**CHP**	**Other**	**TOTAL**
Austria							1		1		**2**
Belgium	1	2		4	2	1					**10**
Canada					1	1		4			**6**
Czech Republic	1	4	4	2	1		2	1	3	1	**19**
France					1	1		1		1	**4**
Germany	1	2	2	2	1	1		2	2		**13**
Hungary	1										**1**
Italy				1	1			1	1		**4**
Japan	1	1		1			1				**4**
Korea	2	2		2							**6**
Mexico		1		1						1	**3**
Netherlands	1	1		1	1	1		2	2	2	**11**
Slovak Republic	1	1							1		**3**
Sweden							1			1	**2**
Switzerland	2			1	1		1		2		**7**
United States	1	2	1	3	1	1		1	1	5	**16**
NON-OECD MEMBERS											
Brazil	1	1		1			3			1	**7**
China	3	3		2	4		3	4	1		**20**
Russia	1	2	1	1	1				5		**11**
South Africa		1								1	**2**
INDUSTRY CONTRIBUTION											
EDF	1										**1**
EPRI	1	1		1	1				1	1	**6**
ESAA		8	5	3	1					3	**20**
Eurelectric-VGB	1	2	1	1	1	2	2	1		1	**12**
TOTAL	**20**	**34**	**14**	**27**	**18**	**8**	**14**	**17**	**20**	**18**	**190**

It is also clear that a price of 30 USD per tonne of CO_2 is probably well below that needed to achieve the ambitious objectives some OECD countries have set for themselves in terms of carbon reduction. Issues like these highlight the importance of sensitivity analyses (see Part II) that will allow interested readers to compare the results of Part I with estimates based on their own assumptions.

Uncertainty has also increased *because of* liberalisation. The opening of energy markets to competition required much more detailed re-regulation and careful market design. Where previously a set of commissioners would simply decide on retail prices and let a vertically integrated monopolist get on with it, today a complex interplay of legal, institutional and technological developments determines market outcomes in a frequently unforeseeable manner.

On top of that, security of supply concerns for gas, the technological and regulatory uncertainties surrounding carbon capture and storage, feed-in tariffs of limited duration for renewables, and a still evolving situation for nuclear energy all increase uncertainty, affect technology choices and make for a far larger set of contingencies than in the past that energy decision makers need to deal with. All of these factors affect the cost of technologies, sometimes decisively so, far beyond the possibilities of a single publication to capture them.

The third factor increasing the uncertainty surrounding the presented cost figures pertains to the evolution of the generating technologies. After two decades of relative stability, the power sector abounds with a significant number of new technological developments. A new generation of nuclear power plants with increased economic and safety performance is beginning to be deployed, higher efficiency coal plant is now more available, promising up to 50% more power from the same coal input compared to plant that it might be replacing, renewable energies (especially wind) are attracting large investments in many countries. A potentially large change, however, is not likely to happen in generation but in network operation, basically at the distribution level. "Smart metering" and real-time pricing have the potential to increase demand elasticities and will flatten load curves. "Smart grids" will be able to connect increasingly disconnected consumption and production sites. During the lifetime of most plants commissioned in 2015 (those that are considered for this study), the owners of electric cars may form a sizeable share of their customers. As of today, it is largely unknown how these factors will affect the system costs of different technologies.

A fourth source of uncertainty stems from the lack of recent OECD experience with construction of both existing and new technologies, since new construction of power generating plants has been limited, and not technically diverse. In the last decade, the majority of new generating plant constructed in OECD countries has been either gas (especially combined cycle gas turbines) or new renewables, especially onshore wind. Hence, within the OECD, there has been very little new build experience in new nuclear plant outside Asian region, notably Korea, and relatively little new coal build outside the United States and a small group of European countries. This creates uncertainty as to what actual construction and operating costs will be, especially for new generations of technologies. There is considerable confidence that costs will fall as more units are built and operating experience accumulates; technological progress in areas such as solar and offshore wind is also likely to be considerable. But none of these moves can be predicted with certainty.

A high level of uncertainty surrounds also carbon capture and storage (CCS). For the first time, this edition includes the cost of carbon capture technologies applied to coal-fired power plant (the costs of transporting and storing carbon have not been included). There is no commercial operating experience for this technology, since this technology is yet to be demonstrated at a commercial scale in power plant applications. Only a few demonstration plants are likely to be operating in the next few years. Nonetheless, estimates of the costs of carbon capture are provided, as a reference, since this will be an essential decarbonising technology, but the uncertainty of these estimates must be underlined.

A fifth source of uncertainty concerns the rapid changes in all power plant costs that have been observed in the last five years or so. The period from 2004 to 2008 saw an unprecedented level of inflation of power plant costs, covering all construction materials, but especially main mechanical components, electrical assembly and wiring, and other mechanical equipment. In this period, cost rises of at least 50% were observed in many locations. Inflation had an impact on different technologies to different degrees, but all have been affected. Since mid 2008, the global crisis has lessened these inflation pressures, although prices for many components have been slow to drop. Depending on when precisely cost estimates have been performed, the outcomes may vary quite widely even for the same technology in the same location.

Projected Costs of Generating Electricity estimates the levelised lifetime costs of continuous baseload power production from an individual plant. It does not take account of costs of transmission, distribution and impacts on the electricity system as a whole. And yet, different technologies have very different impacts on these costs. It is well known, for instance, that non-dispatchable (intermittent) renewables such as wind and solar require back-up capacity, whose level depends on the type of grid and its flexibility. This issue is discussed more fully in the boundary chapter "System Effects of Renewable Power Generation" in Part II. Another question is how classic baseload technologies such as nuclear and coal plants will cope with the ever-growing daily and seasonal peaks in power demand that will require more flexible electricity systems. Will they be penalised for their inability to react quickly to changing supply and demand conditions or will they benefit from smoothed load curves? The answer will probably depend on relative shares and local conditions for demand and supply variations. Again, providing a single estimate, even with the possibility to perform sensitivity analysis, has limited relevance.

Nonetheless, despite the uncertainties, the LCOE methodology provides a very useful basic reference. If this sounds defensive, the authors would like to vigorously affirm that this is not a weakness of the methodology (for which there is simply no alternative) or a shortcoming of the study but the sign of an ever more complex electricity world. Policy makers, academics and journalists need benchmarks for discussion. At the same time, they need to be aware of the limitations of the data, and avoid misinterpretations.

Methodology, conventions and key assumptions

This chapter presents the EGC Spreadsheet model used to calculate levelised average lifetime costs and the methodological conventions and key assumptions adopted to ensure consistency between cost estimates of different countries.

The philosophy and methodology behind the calculation of levelised average lifetime costs are discussed below, in particular addressing the issue of discounting. It is obvious that only a limited number of parameters can be included in any general model and that a number of factors that have not been taken into account may and do have an influence on costs. A number of additional specific methodological points, which bear on issues outside the actual calculations of the spreadsheet model used for the calculations of LCOE in *Projected Costs of Generating Electricity* (such as the treatment of corporate taxes or risk) are discussed in Chapter 8 on "Financing Issues".

2.1 The notion of levelised costs of electricity (LCOE)

The notion of levelised costs of electricity (LCOE) is a handy tool for comparing the unit costs of different technologies over their economic life. It would correspond to the cost of an investor assuming the certainty of production costs and the stability of electricity prices. In other words, the discount rate used in LCOE calculations reflects the return on capital for an investor *in the absence* of specific market or technology risks. Given that such specific market and technology risks frequently exist, a gap between the LCOE and true financial costs of an investor operating in real electricity markets with their specific uncertainties is usually verified. For the same reason, LCOE is also closer to the real cost of investment in electricity production in regulated monopoly electricity markets with loan guarantees and regulated prices rather than to the real costs of investments in competitive markets with variable prices.[1]

The question of discounting

Despite these shortcomings, LCOE remains the most transparent consensus measure of generating costs and remains a widely used tool for comparing the costs of different power generation technologies in modelling and policy discussions. The calculation of the LCOE is based on the equivalence of the present value of the sum of discounted revenues and the present value of the sum of discounted costs. The LCOE is, in fact, equal to the present value of the sum of discounted costs divided by total production adjusted for its economic time value. Another way of looking at LCOE is that it is equal to the price for output (electricity in our case) that would equalise the

1. Due to a number of technical and structural determinants such as the non-storability of electricity, the variability of daily electricity demand or the seasonal variations in both electricity supply and demand, electricity prices, in particular spot prices, can be very volatile where these are allowed to fluctuate.

two discounted cash-flows. In other words, if the electricity price is equal to the levelised average lifetime costs, an investor would precisely break even on the project. This equivalence of electricity prices and LCOE is based on two important assumptions:

a) The interest rate "*r*" used for discounting both costs and benefits is stable and does not vary during the lifetime of the project under consideration. In keeping with tradition, also this edition of the *Projected Costs of Generating Electricity* has worked both with a 5 % and a 10 % discount rate.

b) The electricity price "$P_{Electricity}$" is stable and does not change during the lifetime of the project. All output, once produced, is immediately sold at this price.

The actual equations should clarify these relationships. With annual discounting, the LCOE calculation begins with equation (1) expressing the equality between the present value of the sum of discounted revenues and the present value of the sum of discounted costs. The subscript "*t*" denotes the year in which the sale of production or the cost disbursement takes place. All variables are real and thus net of inflation. On the left-hand side one finds the discounted sum of all benefits and on the right-hand side the discounted sum of all costs. The different variables indicate:

$Electricity_t$:	The amount of electricity produced in year "t";
$P_{Electricity}$:	The constant price of electricity;
$(1+r)^{-t}$:	The discount factor for year "t";
$Investment_t$:	Investment costs in year "t";
$O\&M_t$:	Operations and maintenance costs in year "t";
$Fuel_t$:	Fuel costs in year "t";
$Carbon_t$:	Carbon costs in year "t";
$Decommissioning_t$:	Decommissioning cost in year "t".

$$\sum_t (Electricity_t * P_{Electricity} * (1+r)^{-t}) = \sum_t ((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t)*(1+r)^{-t}) \quad (1).$$

From (1) follows that

$$P_{Electricity} = \sum_t((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t)*(1+r)^{-t}) / (\sum_t(Electricity_t*(1+r)^{-t})) \quad (2),$$

which is, of course, equivalent to

$$LCOE = P_{Electricity} = \sum_t((Investment_t + O\&M_t + Fuel_t + Carbon_t + Decommissioning_t)*(1+r)^{-t}) / (\sum_t(Electricity_t*(1+r)^{-t})) \quad (2)'.$$

Formula (2)' is in effect the formula used in this study to calculate levelised average lifetime costs on the basis of the costs for investment, operations and maintenance, fuel, carbon emissions and decommissioning provided by OECD member countries and selected non-member countries, and industry organisations.[2] It is also the formula that has been used in previous editions of the IEA/NEA series on the cost of generating electricity, as well as in most other studies on the topic.

The IEA/NEA Ad hoc Expert Group on Electricity Generating Costs that has overseen the elaboration of this study, nevertheless had some discussion about the appropriateness of dividing each year's output in the denominator ($Electricity_t$) by the discount factor $(1+r)^t$ corresponding to any given year. The reason is easy to see. Equation (2)' seems to discount each year's physical value

2. For combined heat and power (CHP) plants a heat credit is subtracted from total unit costs to establish an equivalent of the levelised costs of producing *only* electricity.

of output measured in MWh by the exponentially rising time preference factor *(1+r)*^{t}. Discounting physical values, however, does not seem to make intuitive sense, since physical units neither change magnitude over time, nor do they pay interest. This intuition, however, needs to be qualified. While it is true that an MWh of electricity does not pay interest, its only economic function is to produce a revenue stream that *does* pay interest.[3] From today's point of view, an MWh produced this year thus does not have the same economic value as does an MWh produced next year. What is discounted is the value of output, that is the physical production times its price, $P_{Electricity}$ in the above formula, and not output itself. It is only after mathematical transformation that it appears *as if* physical production was discounted.

The EGC Expert Group thus quickly came to the – universally accepted – conclusion that the operation that *seems* to discount physical output is the result of the necessary discounting of the monetary value of output, i.e. its price. This substitution of physical output for its economic value (price) is possible because the nominal, undiscounted price stays the same throughout the operating lifetime of the plant. The correct time value of the annual revenue flow is now obtained by adjusting output rather than price with the correct discount factor. In fact it is not output *per se* that is discounted but its economic value, which is, of course, standard procedure in cost-benefit accounting.

Calculating the costs of generating electricity

Before presenting the different methodological conventions and default assumptions employed to harmonise the data received from different countries, one major underlying principle needs to be recalled: the study on *Projected Costs of Generating Electricity* is concerned with the levelised cost of producing baseload electricity at the plant level. While this seems straightforward enough a principle, it has implications that are frequently less evident to the casual reader but need to be kept in mind.

First, this means that the assumptions on load factors will systematically be at the upper limit of what is technically feasible. For nuclear, coal and gas plants, a standard load factor of 85% has thus been chosen. This is higher than the average observed load factors in practice, and particularly so for gas plants. The reason is that operators may choose to shut them down during baseload periods, when prices are low, due to their higher marginal costs. However, such considerations of portfolio optimisation do not enter into the methodology of this study.

Second, the very notion of plant-level costs implies that this study does not take into account system costs, i.e. the impact of a power plant on the electricity system as a whole. This is an issue that concerns all technologies, for instance in terms of location or grid connection. The issue of system externalities, however, is a major issue for variable (non-dispatchable) renewable energies such as wind and solar. Since electricity cannot be stored, demand and supply need to be balanced literally every second.[4]

3. The argument that an MWh of electricity serves to enable production and consumption, of course, does not change anything but only transposes the problem on a different plane. Once used in production, it is the revenue stream generated by this production, or alternatively the income stream used in consumption, that is subject to inter-temporal optimisation and hence discounting. See Babusiaux (1990) for a succinct exposition of the issue.

4. In the mediumterm, "smart metering", "smart grids" and progress in storage technology might all contribute to alleviating such constraints.

The intermittent availability of electricity from wind turbines or solar panels thus puts further strains on the ability to balance the system. While improvements in the mapping and forecasting of wind can help, they do not solve the problem of variability. Even shortfalls announced in advance need to be compensated by other sources of generation that can be mobilised at short notice, namely hydro reserves or peak gas turbines, which otherwise stay idle. Part of the cost of such system's reserves should, thus, in principle, be added to the LCOE of intermittent renewables when compared to other baseload generation sources.[5]

There is no disagreement between experts that such system costs for non-dispatchable renewables exist. There is, however, little agreement (and, in fact, very little information) about their precise amount, which varies with the structure and interconnection of the energy system and the share of intermittent renewables. Chapter 8 in Part II of this study "System Effects of Renewable Power Generation" will provide an overview of the available research on the topic but without offering any conclusive estimates.

Third, the concentration on plant-level data also concerns carbon capture and storage (CCS), as noted earlier a promising but technically and financially yet unproven key technology in commercial-sized power plant applications. *Projected Costs of Generating Electricity* only includes the cost of *carbon capture and compression*. It does not consider the costs of transporting and storing the sequestered carbon in final deposits. Relevant plants were thus identified with the moniker CC(S), indicating that one would expect the plant to consider storage but that its costs have not been included. It is anticipated that capture and compression will account for a large proportion of total CCS costs. Furthermore, transport and storage costs vary enormously with volume and distance of transport and type of sink. Best estimates to date put the additional cost of transport and storage of CO_2 between USD 10 and 14 per MWh. The study concentrates once more exclusively at plant-level costs and readers will have to bring their own judgement to bear on the issue of CO_2 transport and storage, taking into account locational and environmental issues.

Finally, as has already been mentioned in the Introduction, this study considers costs *net* of all forms of government interventions as far as OECD countries are concerned. This means the costs calculated are *social resource costs,* the cost of society to build and operate a given plant, independent of all taxes, subsidies and transfers. It is obvious that the latter, say in form of a tax credit or a faster depreciation schedule, can have a major impact on the profitability of a given project. Thus, they do affect the competitiveness of certain technologies over and above their social resource cost. This study, however, only considers the cost of investment *net* of government interventions.

Keeping in mind these *caveats* concerning the nature of the analysis performed in *Projected Costs of Generating Electricity,* we can now provide an overview of the more detailed methodological procedures employed to calculate the LCOE for a large number of different technologies from different countries. It is obvious that this requires treading a fine line between capturing the specifics of each individual case on the one hand and, on the other, harmonising data in order to render it comparable.

5. Our discussion focuses only on technical system costs. Pecuniary system costs, however, can also be considerable. At certain moments, prices for baseload electricity in Europe have been very low or negative for short periods of time due to an existing situation of overcapacity in the system which is signalled by the market.

2.2 The EGC spreadsheet model for calculating LCOE

The actual calculations of the LCOE for both OECD and non-OECD countries were undertaken with the help of a simple spreadsheet model according to a set of common basic assumptions (see below). Its key purpose was to generate LCOE data in a transparent and easily reproducible manner. The IEA/NEA spreadsheet model is intended to be a flexible, transparent structure able to accommodate a large number of different assumptions without losing the underlying coherence of the exercise of comparing national cost figures for power generation over different technologies.

It is obvious that only a limited number of parameters can be included in any model that works across the board for nearly 200 plants from 24 different sources (16 OECD member countries, 4 non-member countries and 4 industrial companies or industry organisations, EDF, the Energy Supply Association of Australia, US EPRI and Eurelectric-VGB). In practice, a number of parameters *not* included in the model may have significant influence on actual electricity generating costs. First and foremost, government policies ranging from market design and competition rules to loan guarantees and implicit or explicit subsidies and taxes, have not been included in the costs calculations. One may consider this a shortcoming of the study. In reality, any inclusion of parameters beyond raw, technical costs would have rendered any such comparative study over more than a small number of countries meaningless. This does not mean that more in-depth research on the basis of a broader set of factors affecting generating costs in individual cases might not yield useful and interesting results.

The EGC spreadsheet model is contained in a number of Excel worksheets. It is based on a similar, slightly simpler, model used in preceding versions of *Projected Costs of Generating Electricity* since 1983. Its main improvements were in the readability and complete transparency of all operations as well as the addition of dedicated modules for fuel prices, carbon prices and CHP heat credits. In the following, the different elements of the model and its working are briefly presented. For all quantitative assumptions see Section 3 on "Methodological conventions and key assumptions for calculating LCOE with the EGC spreadsheet model" below.

Part I

Part I of the IEA/NEA spreadsheet model contains five basic modules (identification, basic assumptions, questionnaire information, generating costs and lifetime generating costs) that provide all necessary information for readers only interested in the input and the output data but not the working of the model and its underlying assumptions itself.

(1) Identification

Module 1 provides the information that associates a given set of data with a specific country, fuel category, technology and type (if applicable). It also specifies in which national currency unit (NCU) the data is provided.

(2) Basic assumptions

The basic assumptions specify the capacity, the load factor, the lifetime of the plant and the discount rate. Capacity depends on the individual plant. Lifetimes are harmonised for all plants of a given technology, the generic lifetime for each technology is reported below under "Methodological conventions". The load factor is fixed either by the general assumption of 85% (for nuclear, coal, and gas) or by national assumptions (for renewables). All calculations are done for the two discount rates, 5% or 10%.

In addition, module 2 specifies the fuel price for the technology in question and the carbon price. The commissioning date (31.12.2015) and the NCU/USD exchange rate (national currency units per US dollar, average exchange rate for 2008) are also reported (see Table 2.1 below).

Table 2.1: National currency units (NCU) per USD (2008 average)	
Australia	1.19
Austria	0.68
Belgium	0.68
Brazil	1.83
Canada	1.07
China	6.95
Czech Republic	17.07
France	0.68
Germany	0.68
Hungary [6]	0.68
Italy	0.68
Japan	1 03.36
Korea	1 102.50
Mexico [7]	1.00
Netherlands	0.68
Russia	24.85
Slovak Republic	21.36
South Africa	8.20
Spain	0.68
Sweden	6.59
Switzerland	1.08
United States	1.00
Source: OECD Statistics at www.oecd.org.	

(3) Questionnaire information

Module 3 is designed to receive the principal information from the questionnaires that were sent out by the Secretariat for completion by member countries and experts. It contains entries for the costs of pre-construction, construction, contingency, refurbishment and decommissioning, as well as fixed and variable operations and maintenance, fuel, carbon and waste management. The entries stretch from the beginning of pre-construction, over 2015 (commissioning) until 2085 (end of decommissioning for nuclear power plants).

(4) Generating costs

Module 4 contains the results of the IEA/NEA spreadsheet model in terms of LCOE per MWh of electricity. The results are reported separately for the individual cost items as well as for total capital costs, total variable costs and, of course, total generating costs, the key figure for *Projected Costs of Generating Electricity*. The results are derived by feeding the numbers of modules 2 and 3 into the fuel, carbon and CHP modules of Part II and into the discounting schedules I (NCU) and II (USD) of Part III.

The results are reported once in NCU and twice in USD, in order to verify the consistency of the different elements. The first set of results reported in USD is attained by converting the NCU results, obtained through bottom up calculations on the basis of discounting schedule I (NCU). The second set of results reported in USD is obtained through bottom-up calculations on the basis of discounting schedule II (USD). When the two figures are consistent, there is high probability that the model is working correctly.

(5) Lifetime generating costs

Module 5 reports total discounted generating cost as well as LCOE over the lifetime in a synthetic manner.

Part II

Part II contains the fossil fuel module (module 6), the CO_2 or carbon module (module 7) and the CHP module for calculating heat credits (module 8). In principle, these modules work autonomously on the basis of the information provided in module 2 and which is then transformed on the basis of generic technical assumptions, such as carbon content or conversion efficiencies. Where available, the generic technical assumptions were substituted with country-specific national assumptions.

(6) Fossil fuel module

The Fossil fuel module calculates fuel costs per MWh on the basis of price information for coal in USD per tonne and for gas in USD per MMBtu. Prices for coal are thus converted into prices per GJ. To this aim, where harmonised fuel prices have been used, for traded hard coal in importing countries, it has been assumed in the absence of country-specific indications that a tonne of hard coal corresponds to 25 GJ of energy per tonne based on the IEA latest statistical information available.

In the case of lignite, which is domestically produced and consumed, and quite heterogeneous, national information for both prices and heat content were used. Fuel costs for both coal and gas, are subsequently adjusted by the electrical conversion efficiency of the technology in question.

(7) CO_2 module

The CO_2 module calculates the carbon cost per MWh. Whenever available, national data on carbon emissions per MWh was used. Otherwise data was derived from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (Chapter 2 "Stationary Combustion", p. 2.16). Typically, carbon emissions are around 100 tCO_2/TJ for hard coal and 50 tCO_2/TJ for gas. With standard electric conversion factors of 40% and 55%, this amounts to emissions of 0.9 tCO_2/MWh for electricity from hard coal and of 0.33 tCO_2/MWh for electricity from gas-fired power generation.

The generic assumption for carbon prices was USD 30 per tonne of carbon for all OECD countries and zero for non-member countries.

In the case of CHP plants, *all* carbon emissions were allocated to electricity production. This produces at first sight counter-intuitive results since carbon emissions per MWh are thus higher than at electricity-only plants. However, in the actual cost calculations, this effect vanishes, since a heat credit is applied to the unit costs of CHP. Including total CO_2 emissions for CHP to electricity output not only raises carbon costs, but it also raises the credit for heat output (since no carbon costs apply here). The final result fully reflects the economic cost advantages of CHP and is consistent with the LCOE methodology.

(8) CHP module for calculating heat credit

The CHP module for calculating heat credit continues an accounting convention used in earlier EGC studies. Given that CHP produce heat as well as power, one cannot impute the total generating costs to power alone. Parcelling out cost shares, however, is highly impractical since heat and power are genuine joint products. The convention adopted is thus to impute to power generation the total costs of generation *minus* the value of the heat produced.

In order to arrive at a CHP heat credit per MWh of electricity, one thus needs to establish first the total value of the heat produced over the lifetime of the plant by multiplying total heat output by its per unit value. The total value of the heat output is then divided by the lifetime electricity production to obtain the per MWh heat credit.

Part III

(9) Discounting schedule I (NCU) with variable cost sub-model

(10) Discounting schedule II (USD) with variable cost sub-model

Part III contains the two discounting schedules starting from the year in which construction begins and ending in 2075. Discounting schedule I is in terms of NCU and discounting schedule II in terms of USD. Both have been arranged to allow maximum transparency both in terms of inter-temporal costs (vertically) and in terms of the different cost components (horizontally). Its structure is determined by the modellers according to the methodological conventions adopted for calculating LCOE with the EGC spreadsheet model.

2.3 Methodological conventions and key assumptions for calculating LCOE with the EGC spreadsheet model

The purpose of these methodological conventions for calculating levelised average lifetime costs with the EGC spreadsheet model is to guarantee comparability of the data received, all the while preserving the country-specific informational content. Defining them in a satisfactory manner means finding a careful balance between too much and too little homogenisation. These conventions have two distinct functions:

1. Assumptions on certain key parameters such as discount rates, lifetimes or fuel and carbon prices need harmonisation because they have a decisive impact on final results. Different fuel price assumptions inside a single region, say Europe, would bury all other information but reveal little about national conditions for electricity generation costs. Differences *between* regions or in certain large countries, however, were acknowledged.

2. In the light of occasionally incomplete or ambiguous country submissions, methodological conventions serve to complete and harmonise them (this concerns items such as contingency assumptions, residual value, decommissioning costs and schedules, etc.). *Wherever possible, national assumptions were taken in these cases.*

Decisions on methodology were prepared by the IEA and NEA Secretariats and taken by the EGC Expert Group. An overview of conventions and key assumptions is provided below:

Discount rates

The levelised costs of electricity were calculated for all technologies for both 5% and 10%.

Fuel prices

Average OECD import price assumptions for hard (black) coal and gas were provided by IEA Office of the Chief Economist and are comparable with the assumptions used in the World Energy Outlook (IEA, 2009). The average calorific values associated to these prices are based on the IEA energy statistics and balances of OECD countries. For the heat content of coal, national assumptions were used wherever available, which was the case for the great majority of countries.[6] The prices used are provided in standard commercial units for coal (tonnes) and gas (MMBtu). In parentheses are given the prices per gigajoule (GJ, $10^9\ m^2 \cdot kg \cdot s^{-2}$), which alone is an SI unit, *i.e.* part of the International System of Units. All prices apply to the plant gate:

Hard coal (OECD member countries):	USD 90 per tonne (USD 3.60 per GJ);
Brown coal (not traded):	National assumptions for both price and heat content;
Natural gas (OECD Europe):	USD 10.3 per MMBtu (USD 9.76 per GJ);
Natural gas (OECD Asia):	USD 11.7 per MMBtu (USD 11.09 per GJ).

In the case of the following three countries, all of which are large coal and gas producing countries, where domestic prices can decouple from world market prices, the study has adopted national assumptions for prices and heat content as provided by the country in question.

Australia	
Hard coal	USD 26.65 per tonne (USD 1.25 per GJ);
Gas	USD 8.00 per MMBtu (USD 7.58 per GJ).

6. In the absence of national mass-to-heat conversion factors, the study uses a default factor of 25 GJ per tonne for black coal.

Mexico	
Hard coal	USD 87.50 per tonne (USD 3.32 per GJ);
Gas	USD 7.87 per MMBtu (USD 7.5 per GJ).
United States	
Hard coal	USD 47.60 per tonne (USD 2.12 per GJ);
Gas	USD 7.78 per MMBtu (USD 7.4 per GJ).

National fuel price assumptions were also used for non-OECD countries:

Brazil	
Hard coal	USD 33.09 per tonne (USD 1.85 per GJ);
Gas	USD 8.13 per MMBtu (USD 7.71 per GJ).
China	
Hard coal	USD 86.34 per tonne (USD 2.95 per GJ);
Gas	USD 4.78 per MMBtu (USD 4.53 per GJ).
Russia	
Hard coal [7]	USD 78.00 per tonne (USD 2.66 per GJ);
Gas	USD 6.30 per MMBtu (USD 5.97 per GJ).
South Africa	
Hard coal	USD 14.63 per tonne (USD 0.82 per GJ).

Costs of the nuclear fuel cycle

A number of countries provided cost data on different components of the fuel cycle. However, in order to work with the EGC spreadsheet model, cost data in terms of USD/MWh needed to be defined on a harmonised basis. For uranium prices, an indicative value that did not directly enter calculations of USD 50 per pound of U_3O_8 was used for reference only.

Front-end of nuclear fuel cycle (Uranium mining and milling, conversion, enrichment and fuel fabrication):	USD 7 per MWh (USD 1.94 per GJ);
Back-end of nuclear fuel cycle (Spent fuel transport, storage, reprocessing and disposal):	USD 2.33 per MWh (USD 0.65 per GJ).

Wherever available, in a format compatible with the EGC spreadsheet model, national data was taken.

Carbon price

The EGC project works with a harmonised carbon price common to all OECD countries over the lifetime of all technologies.

OECD countries	USD 30 per tonne of CO_2;
Non-OECD countries	No carbon price.

Heat credit

The allowance for heat production in combined-heat-and-power (CHP) plants was fixed at USD 45 per MWh of heat for OECD member countries.

7. The price refers to a tonne of coal equivalent.

Lifetimes

The EGC project harmonised expected lifetimes for each technology across countries in the following manner:

Wave and tidal plants	20 years;
Wind and solar plants	25 years;
Gas-fired power plants	30 years;
Coal-fired power and geothermal plants	40 years;
Nuclear power plants	60 years;
Hydropower	80 years.

Decommissioning and residual value

At the end of a plant's lifetime, decommissioning costs were spread over a period of 10 years for all technologies. In case of any positive "residual value" after operating the lifetime of a plant (iron scrap value, left-over carbon permits, etc.), there was a possibility to also record it. For fossil fuel and CC(S) plants the residual value of equipment and materials shall normally be assumed to be equal to the cost of dismantling and site restoration, resulting in a zero net costs of decommissioning. For wind turbines and solar panels, rather than decommissioning, in practice what takes place at the end of their operating lifetime is a replacement of equipment and the scrap value of the renewable installation is estimated to amount to 20% of the original capital investment. However, no country reported such residual value. In any case, wherever available, the submitted national values were used. Where no data on decommissioning costs was submitted, the following default values were used:

Nuclear energy	15% of construction costs;
All other technologies	5% of construction costs.

The question of decommissioning had lead to discussions in the EGC Expert Group given that due to the levelised cost methodology, decommissioning costs become very small once discounted over 60 years, the assumed lifetime of a nuclear plant.[8] This can seem at odds with the fact that once decommissioning costs do come due they still represent sizeable amounts of money.[9] For an investor however contemplating an investment today, decommissioning costs are too far in the future and not a decisive criterion from a financial perspective. Inside the framework of the LCOE methodology of this study, the actual methodological procedure is straightforward and with that procedure levelised decommissioning costs accounted for after the end of the lifetime of a project become indeed negligible once discounted at any significant discount rate.

Treatment of fixed O&M costs

Fixed O&M costs were allocated on an annual basis.

8. In the median case, for nuclear plants, at 5% discount rate, a cost of decommissioning equivalent to 15% of construction costs translates into 0.16 USD/MWh once discounted, representing 0.2% of the total LCOE. At 10%, that cost becomes 0.01 USD/MWh once discounted, and represents around 0.015% of the total LCOE.

9. The EGC study assumes a decommissioning cost of 15% of construction costs. This share may be higher in specific cases. Experiences with decommissioning costs and practices in OECD countries are explored in (NEA, 2003). The study reports average decommissioning costs of 300-400 USD/kWe (depending on reactor type) with a standard deviation of 70-200 USD/kWe. For a 1 000 MW reactor, total decommissioning costs (not discounted) would thus amount to 300 to 400 million USD.

Contingency payments

Contingencies, cost increases resulting from unforeseen technical or regulatory difficulties, are included in the last year of construction. The following conventions have been adopted if national data was not available:

Nuclear energy (except in France, Japan, Korea and United States), CC(S) and offshore wind:	15% of investment costs;
All other technologies:	5% of investment costs.

The reasons for this decision are that CC(S), offshore wind, as well as nuclear energy in countries with only a small number of facilities constitute (at least to some extent) first-of-a-kind (FOAK) technologies that require a higher contingency rate. In countries with a large number of nuclear plants, such as France, Japan, Korea and the United States, technical and regulatory procedures can be considered as running comparatively smoothly so that contingency payments higher than those for other technologies are not warranted.[10]

Capacity

Wherever the distinction was made in submission, net rather than gross capacity was used for calculations.

Projected Costs of Generating Electricity compares plants which have very different sizes, e.g. the costs of fossil fuel plants with the cost of other technologies which normally have significantly larger size units, for example nuclear power plants. The EGC methodology does not however take into account the economies of larger multiple unit plants. It is estimated that new units built at an existing site may be 10-15% cheaper than greenfield units if they can use (at least partially) existing buildings, auxiliary facilities and infrastructure. Regulatory approvals are also likely to be more straightforward. The number of units commissioned at the plant site also leads to a non-linear reduction of per unit capital costs. If a two-unit plant is taken as a basis for comparison, the costs of the first unit may be near 25% higher because of the additional works required for the next units. For a 3-4-unit plant, capital costs may be 8-12%, and for the 5-6-unit plant 15-17%, lower than for the basic two-unit plant.

Construction cost profiles

Allocation of costs during construction followed country indications. It was linear in cases where no precise indications were provided.

In the absence of national indications for the length of construction periods, the following default assumptions were used:

Non-hydro renewables	1 year;
Gas-fired power plants	2 years;
Coal-fired power plants	4 years;
Nuclear power plants	7 years.

10. In the case of the United States, national provided contingency rates were used which correspond to 15% of investment costs for the United States and 11% for US EPRI.

Transmission and grid connection costs

Transmission and grid connection costs were disregarded even where indicated. As noted earlier the study exclusively compares plant-level production costs.

Load factors

A standard load factor of 85% was used for all gas-fired, coal-fired and nuclear plants under the assumption that they operate in baseload. While it is clearly understood that many gas-fired power plants are frequently used in mid-load or even peak-load rather than in baseload, since the overarching concern of *Projected Costs of Generating Electricity* is with baseload, the 85% assumption is used as a generic assumption also for gas-fired power plants.

Country-specific load factors were used for renewable energies, since they are largely site-specific.

Conclusions

This concludes the overview of the conventions and key assumptions adopted for calculating the levelised cost of electricity generation in *Projected Costs of Generating Electricity – 2010 Edition*. While individual assumptions can be subject to discussion – and several of them have been the subject of vigorous debate in the EGC Expert Group – one should not lose sight of their essential function, which is to render comparable large amounts of heterogeneous data. In fact, only by rendering the data comparable can the specificity of each individual data set be brought out and assessed.

The key assumptions and methodological conventions presented above should thus not be mistaken for a "Secretariat view" or a "view of the EGC Expert Group". All those involved are sufficiently informed to know that the future cost of power generation is uncertain. Even less so, should these assumptions be mistaken for an official OECD view on the costs of electricity generation. As a whole, the above key assumptions and conventions serve to develop reasonable base cases that can be starting points for finer inquiries.

Readers thus need to make up their own mind. They are assisted in this task by a large number of sensitivity analyses in Part II of this study that show the impact of varying certain key assumptions. *Projected Costs of Generating Electricity* intends to encourage further work and discussion on the costs of power generation rather than to substitute for such more detailed work.

References

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NEA (2003), *Decommissioning Nuclear Power Plants: Policies, Strategies and Costs,* OECD, Paris, France.

OECD Statistics at www.oecd.org.

Technology overview

3.1 Presentation of different power technologies

This chapter presents an overview of the different technologies for electricity generation that have been submitted for the current study. For a first overview, the overnight costs of all electricity generating technologies are provided in Tables 3.1a and 3.1b. Subsequently, this section discusses, for each major power generation category, the geographical coverage of responses, the specific features of the technologies employed and the outlook for particular technologies. A short discussion of the main assumptions used in calculating the levelised cost of electricity (LCOE) is included, as well as a number of qualitative issues in connection with each technology such as future cost trends. Section 3.2 provides an overview table presenting detailed data on electricity generating costs for all 190 of the plants in the study, broken down according to major technology categories.

Table 3.1a: Overnight costs* of electricity generating technologies (USD/kWe) – Mainstream technologies**

Country	Nuclear	USD/kWe	Coal	USD/kWe	Gas	USD/kWe	Onshore wind	USD/kWe
Belgium	EPR-1600	5 383	Bk SC	2 539	Single Shaft CCGT	1 249	3x2MWe	2 615
			Bk SC	2 534	CCGT	1 099	1x2MWe	2 461
					CCGT	1 069		
					CCGT	1 245		
Canada							33x3MWe	2 745
Czech Republic	PWR	5 858	Br PCC	3 485	CCGT	1 573	5x3MWe	3 280
			Br FBC	3 485	CCGT w/CC(S)	2 611		
			Br IGCC	4 671				
			Br FBC w/ BioM	3 690				
			Br PCC w/CC(S)	5 812				
			Br FBC w/CC(S)	6 076				
			Br IGCC w/CC(S)	6 268				
			Br FBC w/BioM and CC(S)	6 076				
France***	EPR	3 860					15x3MWe	1 912
Germany	PWR	4 102	Bk PCC	1 904	CCGT	1 025	1x3MWe	1 934
			Bk PCC w/CC(S)	3 223	Gas Turbine	520		
			Br PCC	2 197				
			Br PCC w/CC(S)	3 516				
Hungary	PWR	5 198						
Italy					CCGT	769	25x2MWe	2 637
Japan	ABWR	3 009	Bk	2 719	CCGT	1 549		
Korea	OPR-1000	1 876	Bk PCC	895	LNG CCGT	643		
	APR-1400	1 556	Bk PCC	807	LNG CCGT	635		
Mexico			Bk PCC	1 961	CCGT	982		
Netherlands	PWR	5 105	Bk USC PCC	2 171	CCGT	1 025	3MWe	2 076
Slovak Republic	VVER	4 261	Br SC FBC	2 762				
Switzerland	PWR	5 863			CCGT	1 622	3x2MWe	3 716
	PWR	4 043						
United States	Adv GenIII+	3 382	Bk PCC	2 108	CCGT	969	100x1.5MWe	1 973
			Bk IGCC	2 433	AGT	649		
			Bk IGCC w/CC(S)	3 569	CCGT w/CC(S)	1 928		
NON-OECD MEMBERS								
Brazil	PWR Siemens/Areva	3 798	Br SUBC PCC	1 300	CCGT	1 419		
China	CPR-1000	1 763	Bk USC PCC	656	CCGT	538	200MWe (Park)	1 223
	CPR-1000	1 748	Bk SC	602	CCGT	583	33x1.5MWe	1 541
	AP-1000	2 302	Bk SC	672			41x0.85MWe	1 627
							30MWe (Park)	1 583
Russia	VVER-1150	2 933	Bk USC PCC	2 362	CCGT	1 237	100x1MWe	1 901
			Bk USC PCC w/CC(S)	4 864				
			Bk SC PCC	2 198				
South Africa			Bk SC PCC	2 104				
INDUSTRY CONTRIBUTION								
EPRI	APWR, ABWR	2 970	Bk SC PCC	2 086	CCGT	727	50x2MWe	1 845
ESAA			Bk SC AC	2 006	CCGT AC	1 678	50x3MWe	2 349
			Bk SC WC	1 958	CCGT WC	1 594		
			Bk USC AC	2 173	OCGT AC	742		
			Bk USC WC	2 114				
			Bk USC AC w/CC(S)	3 919				
			Bk USC WC w/CC(S)	3 775				
			Bk IGCC w/CC(S)	4 194				
			Br SC AC	2 206				
			Br SC WC	2 153				
			Br USC AC	2 374				
			Br USC WC	2 321				
			Br USC AC w/CC(S)	4 087				
			Br USC WC w/CC(S)	3 900				
Eurelectric/VGB	EPR-1600	4 724	Bk	1 952	CCGT	1 201	100MWe (Park)	1 952
			Br	2 102				
			Bk USC w/CC(S)	3 464				

*Overnight costs including pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, excluding interest during construction (IDC).
**Abbreviations are explained in Annex 2 "Glossary of terms and list of abbreviations".
***The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

Table 3.1b: Overnight costs* of electricity generating technologies (USD/kWe) – Other technologies								
Country	Offshore wind	USD/kWe	Hydro	USD/kWe	Solar PV	USD/kWe	CHP	USD/kWe
Austria			Small-2MWe	4 254			CHP Gas CCGT	788
Belgium	1x3.6MWe	6 083						
Canada	200x2MWe	4 498			10MWe (Park)	3 374		
					1MWe (Indus)	4 358		
					0.1MWe (Com)	6 335		
					0.005MWe (Res)	7 310		
Czech Republic			Large-10MWe	19 330	1MWe	7 381	CHP Br Coal Turbine	3 690
			Small-5MWe	11 598			CHP Gas CCGT	1 845
							CHP Municipal Waste	20 502
France	120MWe (Park)	3 824			10MWe	5 588		
Germany	60x5MWe	4 893			0.5MWe (Open space)	3 267	CHP Black Coal	2 966
					0.002MWe (Roof)	3 779	CHP Gas	1 318
Italy					6MWe	6 592	CHP Gas	1 332
Japan			Large-19MWe	8 394				
Netherlands	5MWe	5 727			0.03MWe (Indus)	5 153	CHP Gas CCGT	1 348
					0.0035MWe (Res)	6 752	CHP Gas CCGT	1 855
Slovak Republic							CHP Gas and BioM CCGT	1 112
Sweden			Large-70MWe	3 414				
Switzerland			Small-0.3MWe	4 001			CHP Gas CCGT	1 018
							CHP Biogas	9 925
United States	150x2MWe	3 953			5MWe	6 182	CHP Simple Gas Turbine	798
NON-OECD MEMBERS								
Brazil			Large-800MWe	1 356				
			Large-300MWe	1 199				
			Large-15MWe	2 408				
China			Large-18134MWe	1 583	PV-20MWe	2 878	CHP Black Coal	720
			Large-6277MWe	757	PV-10MWe	3 742		
			Large-4783MWe	896	PV-10MWe	2 921		
					PV-10MWe	3 598		
Russia							CHP Bk PCC	2 791
							CHP Gas CCGT Large	1 442
							CHP Gas CCGT Small	1 949
							CHP Gas Turbine Large	1 285
							CHP Gas Turbine Small	1 615
INDUSTRY CONTRIBUTION								
EPRI							CHP Biomass	2 963
Eurelectric/VGB	100MWe (Close)	3 464	River-1000MWe	3 603	1MWe	6 006		
	100MWe (Far)	4 409	Pump-1000MWe	2 703				

*Overnight costs including pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, excluding interest during construction (IDC).

Nuclear power plants

The total 20 light water reactors reported in the study by 12 OECD member countries, 3 non-member countries and 3 industry organisations include 17 pressurised water reactors (PWRs), 2 boiling water reactors (BWRs), and one generic advanced light water Generation III+ reactor. The net capacity of the reviewed nuclear reactors ranges from 954 MWe in the Slovak Republic to 1 650 MWe in the Netherlands, with the largest site to be constructed in China consisting of 4 units of 1 000 MWe each. Owing to differences in country-specific financial, technical and regulatory boundary conditions, overnight costs for the new nuclear power plants currently under consideration in the OECD area vary substantially across the countries, ranging from as low as 1 556 USD/kWe in Korea (noting the generally low construction costs in that country, as well as its recent experience in building new reactors) to as high as 5 863 USD/kWe in Switzerland, with a standard deviation of 1 338 USD/kWe, median of 4 102 USD/kWe and mean of 4 055 USD/kWe.

Most of the nuclear power cost estimates reviewed in this study are based on advanced Generation III+ reactor designs, with direct or indirect reference to the new models of Areva, General Electric and Toshiba-Westinghouse. These reactor systems promise enhanced safety features and better economics than the many Generation II/III reactors currently in operation.

Table 3.2: Nuclear power plants

Country	Technology	Net capacity MWe
Belgium	EPR-1600	1 600
Czech Republic	Pressurised water reactor (PWR)	1 150
Germany	Pressurised water reactor (PWR)	1 600
Hungary	Pressurised water reactor (PWR)	1 120
Japan	Advanced boiling water reactor (ABWR)	1 330
Korea	Optimised power reactor (OPR-1000)	954
	Advanced power reactor (APR-1400)	1 343
Netherlands	Pressurised water reactor (PWR)	1 650
Slovak Republic	VVER 440/V213	954
Switzerland	Pressurised water reactor (PWR)	1 600
	Pressurised water reactor (PWR)	1 530
United States	Advanced Gen III+ reactor	1 350
NON-OECD MEMBERS		
Brazil	Pressurised water reactor (PWR) Siemens/Areva	1 405
China	Chinese pressurised reactor (CPR-1000) (Fujian)	1 000
	Chinese pressurised reactor (CPR-1000) (Liaoning)	1 000
	AP-1000	1 250
Russia	VVER-1150	1 070
INDUSTRY CONTRIBUTION		
EDF	EPR	1 630
EPRI	Advanced pressurised water reactor (APWR)/ Advanced boiling water reactor (ABWR)	1 400
Eurelectric	EPR-1600	1 600

Each reactor type is characterised by the choice of a neutron moderator and cooling medium, which leads to different fuel designs. The fact that all data submissions in the present study are based on light water reactor technologies reflects the larger industry trend, as more than 88% of the commercial reactors currently in operation worldwide are cooled and moderated by light (ordinary) water.

The two major types of light water reactors are pressurised water reactors (PWRs), including the Russian-designed VVER, and boiling water reactors (BWRs). Only about 7% of the installed capacity in the world use heavy water (deuterium oxide) as coolant and moderator, with the remaining reactors in operation being based on various other designs.

In PWRs, the reactor design chosen for 78% of the planned capacity additions worldwide, water is maintained in liquid form by high pressure; while in BWRs, selected for the remaining 22% of planned capacity, water is kept at a lower pressure and is allowed to boil as it is heated by the reactor. In either type, the heat removed from the core is ultimately used to create steam that drives turbine generators for electricity production.

For light water reactors, the main front-end (before fuel loading in the reactor) fuel cycle steps are: uranium mining and milling, conversion, enrichment and fuel fabrication. The general study assumption adopted for the front-end fuel cycle cost component is USD 7 per MWh of output. At the back end of the fuel cycle, after the unloading of spent fuel from the reactor, two options are available: direct disposal (once-through cycle) or recycling (reprocessing fuel cycle) of spent fuel. In the first option, spent fuel is conditioned after a period of cooling into a form adequate for long-term storage. In the second option, recyclable materials (representing around 95% of the mass of the spent fuel) are separated from the fission products and minor actinides. Without fast breeder reactors, the current method to reuse the separated plutonium is through the use of mixed oxide (MOX) fuel in light water reactors. The high-level waste from reprocessing is then stored, usually in vitrified form, either at reprocessing plant sites or in purpose-built high-level waste repositories. Most countries provided cost estimates for the reactors that operate on once-through cycles; EDF and Japan reported cost data for a reprocessing fuel cycle. The general study assumption for the back-end fuel cycle cost is USD 2.33 per MWh for both closed and once-through fuel cycles.

The study assumption for the average lifetime load factor for calculating the levelised costs of nuclear generation is 85%. The load factor is an important performance indicator measuring the ratio of net electrical energy produced during the lifetime of the plant to the maximum possible electricity that could be produced at continuous operation. In 2008, globally, the weighted average load factor reported for PWRs (a total of 265 reactors) was 82.27%, for BWRs (total of 94 reactors) it was 73.83%, with larger reactors (>600 MWe) exhibiting on average a 2% higher load factor than smaller reactors. Lifetime load factors can be somewhat lower due to start-up periods and unplanned outages. Although somewhat higher than the load factors currently reported for the existing nuclear fleet, the generic assumption of 85% used in this study is consistent with the advertised maximum performance characteristics of the planned Generation III+ reactor designs.

The decommissioning costs of the nuclear power plants reviewed in this study have also been included in the levelised costs calculation. Where no country-specific cost figure was provided, a generic study assumption of 15% of the overnight cost has been applied to calculate the costs incurred during all the management and technical actions associated with ceasing operation of a nuclear installation and its subsequent dismantling to obtain its removal from regulatory control. Disbursed during the ten years following shut-down, the decommissioning cost is discounted back to the date of commissioning and incorporated in the overall levelised costs. While an incontestably important element of a nuclear power plant's operation, decommissioning accounts for a smaller portion of the LCOE due to the effect of discounting. In particular, the fact that for nuclear power plants decommissioning costs are due after 60 years of operation and are discounted back to the commissioning date, makes the net present value of decommissioning in 2015 close to zero, even when applying lower discount rates or assuming much higher decommissioning costs. [1]

1. In the median case, at a 5% discount rate, a decommissioning cost equivalent to 15% of construction costs translates into 0.16 USD/MWh, representing 0.2% of total LCOE. At 10%, that cost becomes 0.01 USD/MWh, and represents around 0.015% of total LCOE.

Coal-fired power generation technologies

Data collected for coal-fired plants is, in general, for current state-of-the-art commercial plants. Only one subcritical plant is included among the dataset of 48 plants of which 40 are from OECD countries, reflecting the declining interest in this outdated technology with low efficiency (30% to 38%), despite its low capital cost. Most subcritical plants operate at steam conditions below 165 bar and 565°C. The laws of thermodynamics mean that higher steam temperatures and pressures allow higher efficiencies to be achieved from potentially smaller equipment. Two classes of such plant are reported: supercritical (SC) and ultra-supercritical (USC). Above an operating pressure of 221 bar (i.e. above the water-steam critical point), water fed into a steam generator does not boil – there is no observable change of state from liquid to gas and no latent heat requirement. Instead, the supercritical water absorbs only heat energy which is converted to mechanical energy in a steam turbine to drive an electrical generator. Modern coal-fired power plants employ supercritical steam conditions to achieve high overall plant efficiency levels, typically between 39% and 46%, measured on the fuel's lower heating value basis (net calorific value). Today, plants use steam at 240 bar to 300 bar and up to 620°C, but in the future, higher pressures and temperatures of 350 bar/700°C could be employed, using nickel-based alloy steels to achieve efficiencies approaching 50%.

There is no agreed definition of when a power plant might be considered ultra-supercritical, although manufacturers would certainly refer to plants operating at supercritical pressure and temperatures above 600°C as USC. Supercritical plant designs are ostensibly simpler than subcritical designs because no steam drum is required to separate steam and water. However, this cost saving is balanced by the use of more expensive materials, more complex boiler fabrication and the need for more precise control systems. On balance, the higher cost of supercritical designs can be justified by the improved fuel efficiency, except in situations where coal costs are very low (e.g. power plants sitting adjacent to easily worked coal reserves).

The EGC study includes a sample of 22 SC and USC plants for the OECD area, with reported thermal efficiencies ranging from 37% in the case of an Australian brown coal SC plant to 46% for hard coal plants in Germany and the Netherlands. Overnight costs for OECD area coal plants consuming black coal range from 807 USD/kWe in Korea to 2 719 USD/kWe in Japan (with a standard deviation of 540 USD/kWe, a median of 2 086USD/kWe and a mean of 1 946 USD/kWe). Overnight costs for OECD area coal plants consuming brown coal range from 1 802 USD/kWe in Australia to 3 485 USD/kWe in the Czech Republic (with a standard deviation of 532 USD/kWe, a median of 2 383 USD/kWe and a mean of 2 308 USD/kWe).

The vast majority of coal-fired plants constructed today burn pulverised coal (PC) to generate steam to drive turbines; this is the technology associated with 29 plants in the dataset. Plant sizes vary from 300 MWe in the Slovak and Czech Republics to 1 560 MWe in the Netherlands within the OECD area, with economies of scale yielding higher efficiencies when larger units are employed. Economies of scale can significantly reduce the cost of multi-unit, coal-fired plants.[2] The present study, however, focuses on costs for individual units.[3]

Pollution control at PC plants is very mature, with a competitive market for dust control equipment, flue gas desulphurisation systems and NOx reduction technologies (catalytic and non-catalytic). Pollutant emissions can be extremely low, with some of the cleanest plants operating in Japan and Denmark.

2. The number of units commissioned at the plant site leads to a non-linear reduction of per-unit capital costs. If a two-unit plant is taken as a basis for comparison, the costs of the first unit may be nearly 25% higher because of the additional works required for the next units. For a three- to four-unit plant, capital costs may be 8-12% lower than for a two-unit plant; a cost saving that grows to 15-17% for a 56-unit plant. Even if additional units are not planned from the outset, new units built at an existing site may be 10-15% cheaper than green-field units, if they can use (at least partially) existing buildings, auxiliary facilities and infrastructure.

3. Except in the case of renewable plants, for obvious reasons.

Table 3.3a: Coal-fired power generation technologies			
Country	Technology	Net capacity MWe	Electrical conversion efficiency %
Belgium	Black supercritical	750	45%
	Black supercritical	1 100	45%
Czech Republic	Brown PCC	600	43%
	Brown fluidised bed	300	42%
	Brown IGCC	400	45%
	Brown FBC w/biomass	300	42%
Germany	Black PCC	800	46%
	Brown PCC	1 050	45%
Japan	Black coal	800	41%
Korea	Black PCC	767	41%
	Black PCC	961	42%
Mexico	Black PCC	1 312	40%
Netherlands	Black USC PCC	780	46%
Slovak Republic	Brown supercritical FBC	300	40%
United States	Black PCC	600	39%
	Black IGCC	550	39%
NON-OECD MEMBER COUNTRIES			
Brazil	Brown PCC	446	30%
China	Black ultra-supercritical PCC	932	46%
	Black supercritical	1 119	46%
	Black supercritical	559	46%
Russia	Black ultra-supercritical PCC	627	47%
	Black supercritical PCC	314	42%
South Africa	Black supercritical PCC	794	39%
INDUSTRY CONTRIBUTION			
ESAA	Black supercritical AC	690	39%
	Black supercritical WC	698	41%
	Black ultra-supercritical AC	555	41%
	Black ultra-supercritical WC	561	43%
	Brown supercritical AC	686	31%
	Brown supercritical WC	694	33%
	Brown ultra-supercritical AC	552	33%
	Brown ultra-supercritical WC	558	35%
EPRI	Black supercritical PCC	750	41%
Eurelectric	Black coal	760	45%
	Brown coal	760	43%

Other coal power technologies are available and attractive in particular applications. Fluidised bed combustion, where a bed of burning coal is suspended in an upward flow of combustion air, can be designed for a wide variety of fuels, including poor quality fuels. With in-bed sulphur retention and relatively low combustion temperatures, such that NOx formation is suppressed, pollutant emissions are low and costly post-combustion clean-up equipment is not required. The largest fluidised bed project is the 460 MWe Łagisza supercritical plant in Poland and manufacturers hope to offer scaled-up designs of up to 800 MWe.

IGCC is very different from conventional coal-fired plants, having more similarities to natural gas combined cycle gas turbine (CCGT) plants. Fuel gas is produced from coal in a gasifier, cleaned and then fed to a gas turbine with heat recovery to generate steam to drive the turbines. Gasification takes place in a pressurised vessel with partial combustion of the coal in a limited supply of air or oxygen, with or without steam. Low emissions are achieved as an inherent part of the process and the potential for high efficiency is comparable to that for supercritical PC plants. However, complexity and cost mean that IGCC has not yet achieved commercialisation, although a small number of demonstration plants are operating successfully at the 250 MWe to 300 MWe scale.[4]

4. The largest plant currently operating, Puertollano IGCC, is 335 MWe (gross), around 300 MWe net.

All coal-fired plant designs can be adapted for CO_2 capture, although this has not been demonstrated at a commercial scale anywhere in the world. Three main technologies are proposed: post-combustion capture, oxyfiring and precombustion capture. Only through development and demonstration will it become clear which might be the most appropriate and successful in a given application. Until then, costs and performance will remain uncertain, although it has to be said that IGCC with CO_2 capture uses components that have been demonstrated at scale in other applications such as those used in the natural gas industry, thus removing some of the uncertainty for this technology.[5]

Table 3.3b: Coal-fired power generation technologies with CC(S)

Country	Technology	Net capacity MWe	Electrical conversion efficiency %
Czech Republic	Brown pulverised combustion w/CC(S)	510	38%
	Brown fluidised bed w/CC(S)	255	37%
	Brown IGCC w/CC(S)	360	43%
	Brown FBC w/biomass and CC(S)	255	37%
Germany	Black pulverised combustion w/CC(S)	740	38%
	Brown pulverised combustion w/CC(S)	970	37%
United States	Black IGCC w/CC(S)	380	32%
NON-OECD MEMBER COUNTRIES			
Russia	Black ultra-supercritical PCC w/CC(S)	541	37%
INDUSTRY CONTRIBUTION			
ESAA	Black ultra-supercritical AC 90% CC(S)	434	31%
	Black ultra-supercritical WC 90% CC(S)	439	33%
	Black IGCC w/85% CC(S)	523	37%
	Brown ultra-supercritical AC 90% CC(S)	416	25%
	Brown ultra-supercritical WC 90% CC(S)	421	27%
Eurelectric	Black ultra-supercritical w/90% CC(S)	760	39%

In the OECD area, the thermal efficiency of SC and USC coal-fired plants with carbon capture equipment is on average 7 percentage points lower than without such equipment, ranging from 30% to 39%. Overnight costs of the 8 coal-fired plants fitted with carbon capture range from 3 223 USD/kWe to 5 811 USD/kWe (with a standard deviation of 812 USD/kWe, a median of 3 851 USD/kWe and a mean of 4 036 USD/kWe).

The sample size was not sufficiently large to allow specific cases to be considered for fluidised bed or IGCC technologies, with or without CO_2 capture. Cost analysis in the median case is therefore based on conventional PC plants, including both SC and USC examples consuming hard coal and brown coal.

Gas-fired power generation technologies

In the last decade, gas-fired power generation has accounted for around 80% of OECD area incremental power generation while coal-fired generation was the preferred generation option in non-OECD countries. Gas-fired CCGT, with low capital cost, short lead times, high efficiency, operational flexibility and low carbon intensity made this technology attractive in the competitive markets of OECD countries as well as in certain non-OECD regions, such as the Middle East, facing the imperative to rapidly address growing power demand or wishing to replace oil-fired plants by gas-fired plants. A total of 24 data submissions were received from 14 countries, of which two plants are equipped with carbon capture. Data was also collected for two gas-fired plants in China, all but two of which concern standard CCGTs.

5. Post-combustion capture using amine solvents has been used at scale for decades to capture CO_2 from hydrogen (refineries), natural gas (extraction to sweeten gas) and in ammonia production. Experience though suggests costs may be lower for IGCC+CC. See also Chapter 10 of this publication on "Carbon Capture and Storage".

Table 3.4: Gas-fired power generation technologies

Country	Technology	Net capacity MWe	Electrical conversion efficiency %
Belgium	Single shaft CCGT	425	58%
	CCGT	400	55%
	CCGT	420	57%
	CCGT	420	57%
Czech Republic	CCGT	430	57%
	CCGT w/CC(S)	387	54%
Germany	CCGT	800	60%
	Gas Turbine	150	38%
Italy	CCGT	400	55%
Japan	CCGT	400	55%
Korea	LNG CCGT	495	57%
	LNG CCGT	692	57%
Mexico	CCGT	446	49%
Netherlands	CCGT	435	59%
Switzerland	CCGT	395	58%
United States	CCGT	400	54%
	AGT	230	40%
	CCGT w/CC(S)	400	40%
NON-OECD MEMBER COUNTRIES			
Brazil	CCGT	210	48%
China	CCGT (Fujian)	340	58%
	CCGT (Shanghai)	340	58%
Russia	CCGT	392	55%
INDUSTRY CONTRIBUTION			
EPRI	CCGT	798	48%
ESAA	CCGT AC	480	56%
	CCGT WC	490	58%
	OCGT AC	297	43%
Eurelectric	CCGT	388	58%

As for other technologies reviewed in the study, overnight construction costs for CCGT plants display great variability across OECD countries, despite the higher degree of standardisation of industry practices for this technology. CCGT plants without CC(S) technology in the OECD area have overnight cost estimates ranging from as low as 635 USD/MWh (in Korea) to 1 747 USD/MWh (in Australia).

Although post-combustion CO_2 capture from a gas plant may be simpler given the more homogenous nature of the exhaust gas, CC(S) seems likely to play a much smaller role for gas-fired power generation than for coal-fired power generation. CCGTs have a lower concentration of CO_2 in flue gas, making extraction less economic, especially taking into account the efficiency penalty incurred and the higher cost of the additional fuel needed. Nonetheless, gas CCS seems likely to be an important part of any decarbonised power sector in the longer term.

On average, CCGT plants benefit from higher efficiency with a median thermal efficiency of 57% for the CCGTs reviewed. The two gas-fired plants with CC(S) quoted above show a reduced efficiency of 54% and 40% respectively.

The recent rapid development of "unconventional gas" resources in the United States and Canada, particularly in the last three years, and the massive development of new LNG projects from Qatar to Australia have transformed the gas market outlook. This increase in supply combined with a decline in demand following the economic crisis, has led to a steep drop in gas prices where these are determined by market fundamentals (rather than linked to a moving average of oil prices as was historically the case in the European and Asian gas markets). How these supply and demand forces play out over the lifetime of a gas-fired power plant remains a very considerable source of uncertainty in determining the LCOE for such plants.

Renewable energy sources

A total of 72 cost data submissions on renewable sources of electricity generation were received, including 18 onshore and 8 offshore wind installations, 17 solar PV and 3 solar thermal installations, 14 hydro units, as well as 3 geothermal, 3 biogas, 3 biomass, 1 tidal and 2 wave-generating technologies.

It should be noted that several of the countries with the greatest potential for renewables have not provided data for the study. For example, data is lacking for offshore wind in countries such as Denmark, Norway, Portugal or the United Kingdom and for solar energy in Spain, by far the largest market for this technology.

Onshore wind: again, the data shows a very wide range, with overnight costs ranging from 1 821 USD/kWe (France) to 3 716 USD/kWe (Switzerland). The reported capacities range from an individual unit of 2 MW to a wind power plant consisting of 200 MW. Reported load factors range from 20% to 41%.

Costs are expected to decline as capacities expand. In retrospect, past cost reductions can be seen to demonstrate a steady "learning" or "experience" rate. Learning or experience curves reflect the reduction in the cost of energy achieved with each doubling of capacity – known as the progress ratio. Assuming a learning rate for onshore wind energy of 7%, investment costs might be expected to decrease consistently to around USD 1 400/kW in 2020.

Offshore wind: the range of overnight costs for the 8 reported offshore wind projects is from 2 540 USD/kWe to 5 554 USD/kWe. Load factors range from 34% to 43%.

Analysis suggests a higher learning rate for offshore investment costs, of 9%, giving an investment cost in 2020 in the range of USD 2 500-3 000/kW.

Solar PV: capacities range from 0.002 MWe (roof) to 20 MWe (open-space industrial); load factors range from 9.7% (Netherlands) to 24.9% (France). Overnight costs exhibit a range from as low as 3 067 USD/kWe for a utility-scale solar PV farm (Canada) to 7 381 USD/kWe (Czech Republic).

Assuming a progress ratio of 18% as suggested by the historical long-term trends in PV development, and rapid deployment driven by strong policy action in the coming decade, investment costs could drop 70% from the current USD 4 000-6 000/kW down to USD 1 200-1 800/kW by 2030, with an important cost reduction of at least 40% already being achievable by 2015 (and -50% by 2020).

Hydro: the cost data is difficult to compare as it covers both small hydro units and pumped storage (from as small as 0.30 MWe upwards) as well as large-scale projects (notably, a 18 GWe project in China). The load factor ranges from 29% to 80%. The overnight cost ranges from a low of 757 USD/kWe to 19 330 USD/kWe.

Geothermal: well-drilling makes up a large share of the overnight costs of geothermal electricity generation, sometimes accounting for as much as one-third to one-half of the total cost of a geothermal project. Capital costs are very site-specific, varying significantly with the characteristics of the local resource system and reservoir. For the three reported projects, the overnight construction costs vary from 1 752 USD/kWe in the United States (for a 50 MWe project) to 12 887 USD/kWe in the Czech Republic (5 MWe); in the Australian submission, the reported figure of 4 095 USD/kWe (500 MWe) is said to be on the lower end of construction costs that can exceed 6700 USD/kWe.

Table 3.5: Renewable energy sources			
Country	Technology	Net capacity MWe	Load factor %
Austria	Small hydro	2	59%
Belgium	Onshore wind	6	29%
	Onshore wind	2	26%
	Offshore wind	3.6	37%
Canada	Onshore wind	99	30%
	Offshore wind	400	37%
	Solar PV (park)	10	13%
	Solar PV (industrial)	1	13%
	Solar PV (commercial)	0.1	13%
	Solar PV (residential)	0.005	13%
Czech Republic	Onshore wind	15	25%
	Large hydro	10	60%
	Small hydro	5	60%
	Solar PV	1	20%
	Geothermal	5	70%
France	Onshore wind	45	27%
	Offshore wind	120	34%
	Solar PV	10	25%
	Biogas	0.5	80%
Germany	Onshore wind	3	23%
	Offshore wind	300	43%
	Solar PV (open space)	0.5	11%
	Solar PV (roof)	0.002	11%
Italy	Onshore wind	50	22%
	Solar PV	6	16%
Japan	Large hydro	19	45%
Netherlands	Onshore wind	3	25%
	Offshore wind	5	41%
	Solar PV (industrial)	0.03	10%
	Solar PV (residential)	0.0035	10%
	Solid biomass and biogas	11	85%
	Solid biomass	20	85%
Sweden	Large hydro	70	40%
	Wave	1 000	35%
Switzerland	Onshore wind	6	23%
	Small hydro	0.3	50%
United States	Onshore wind	150	41%
	Offshore wind	300	43%
	Solar PV	5	24%
	Solar thermal	100	24%
	Solid biomass	80	87%
	Biogas	30	90%
	Geothermal	50	87%
NON-OECD MEMBER COUNTRIES			
Brazil	Large hydro	800	55%
	Large hydro	300	55%
	Large hydro	15	55%
	Biomass (woodchip)	10	85%
China	Onshore wind	200	27%
	Onshore wind	50	27%
	Onshore wind	35	22%
	Onshore wind	30	20%
	Large hydro	18 134	53%
	Large hydro	6 277	34%
	Large hydro	4 783	57%
	Solar PV	20	21%
	Solar PV	10	18%
	Solar PV	10	21%
	Solar PV	10	18%
Russia	Onshore wind	100	32%
INDUSTRY CONTRIBUTION			
EPRI	Onshore wind	100	33%
	Solar thermal	80	34%
ESAA	Onshore wind	149	30%
	Geothermal	500	85%
	Wave	50	56%
	Tidal	304	30%
Eurelectric	Onshore wind	100	21%
	Offshore wind (close)	100	37%
	Offshore wind (far)	100	43%
	Large hydro (river run)	1 000	80%
	Large hydro (pump storage)	1 000	29%
	Solar PV	1	23%
	Solar thermal	1	32%

Combined heat and power (CHP) plants

The present study received 20 submissions for combined heat and power (CHP) plants underlining the importance of this technology in global efforts to reduce greenhouse gas emissions. Other things being equal (in particular the technology and the fuel being used for producing electricity), CHP plants have lower greenhouse gas emissions per unit of useful energy service than power-only plants since heat generated during electricity production is not wasted but used for heating (both room and water heating).

Table 3.6: Combined heat and power (CHP) plants

Country	Technology	Net capacity MWe
Austria	Natural gas – CCGT	405
Czech Republic	Brown coal – boiler/steam turbine	150
	Natural gas – CCGT	200
	Municipal waste incineration	15
Germany	Black coal – back pressure	200
	Natural gas – back pressure	200
Italy	Natural gas	850
Netherlands	Natural gas – CCGT	250
	Natural gas – CCGT	60
Slovak Republic	Natural gas and biogas – CCGT	415
Switzerland	Natural gas – CCGT	400
	Biogas	0.2
United States	Simple gas turbine	40
NON-OECD MEMBERS		
China	Black coal	559
Russia	Black pulverised coal	103
	Gas combined cycle large	415
	Gas combined cycle small	44
	Gas turbine large	101
	Gas turbine small	24
INDUSTRY CONTRIBUTION		
EPRI	Biomass	75

The submission shows that natural gas is by far the most attractive fuel for use in CHP (13 submissions), followed by coal (3 submissions), biomass (2 submissions), biogas and municipal waste (1 each).

The relative competitiveness of CHP depends primarily on the value of the heat generated. This heat value varies widely according to country and the nature of the energy service provided. A heat credit of 45 USD/MWh has been applied in the cost calculations.

Reflecting the heterogeneity of the reported plants, the overnight costs range substantially, from as low as 788 USD/kWe (Austria) to 9 925 USD/kWe (Switzerland).

3.2 Technology-by-technology data on electricity generating costs

Tables 3.7a to 3.7g provide an overview of the main cost information for the 190 power plants reviewed in this study. For each power plant of specified type and installed capacity, the overnight cost column provides one of the most common cost references in the industry, indicating the sum of pre-construction, construction and contingency costs, expressed in USD per kWe of installed electric capacity.

The next column reports investment costs in USD per kWe, which is the sum of overnight costs plus the interest during construction (IDC), calculated at 5% and 10% discount rates. The remaining columns provide the information on decommissioning, fuel[6] and carbon, as well as operations and maintenance costs, expressed in USD per MWh of electricity produced. The final column provides the total levelised cost of electricity (LCOE) over the lifetime of the plant in USD per MWh.

The values for investment, decommissioning and total levelised cost are reported for both 5% and 10% discount rates. Fuel, carbon and operations and maintenance costs per MWh do not change with the discount rate since they are already levelised costs.

Table 3.7a: Nuclear power plants: Levelised costs of electricity in US dollars per MWh

Country	Technology	Net capacity	Overnight costs [1]	Investment costs [2]		Decommissioning costs		Fuel Cycle costs	O&M costs [3]	LCOE	
				5%	10%	5%	10%			5%	10%
		MWe	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	
Belgium	EPR-1600	1 600	5 383	6 185	7 117	0.23	0.02	9.33	7.20	**61.06**	**109.14**
Czech Rep.	PWR	1 150	5 858	6 392	6 971	0.22	0.02	9.33	14.74	**69.74**	**115.06**
France*	EPR	1 630	3 860	4 483	5 219	0.05	0.005	9.33	16.00	**56.42**	**92.38**
Germany	PWR	1 600	4 102	4 599	5 022	0.00	0.00	9.33	8.80	**49.97**	**82.64**
Hungary	PWR	1 120	5 198	5 632	6 113	1.77	2.18	8.77	29.79/29.84	**81.65**	**121.62**
Japan	ABWR	1 330	3 009	3 430	3 940	0.13	0.01	9.33	16.50	**49.71**	**76.46**
Korea	OPR-1000	954	1 876	2 098	2 340	0.09	0.01	7.90	10.42	**32.93**	**48.38**
	APR-1400	1 343	1 556	1 751	1 964	0.07	0.01	7.90	8.95	**29.05**	**42.09**
Netherlands	PWR	1 650	5 105	5 709	6 383	0.20	0.02	9.33	13.71	**62.76**	**105.06**
Slovak Rep.	VVER 440/ V213	954	4 261	4 874	5 580	0.16	0.02	9.33	19.35/16.89	**62.59**	**97.92**
Switzerland	PWR	1 600	5 863	6 988	8 334	0.29	0.03	9.33	19.84	**78.24**	**136.50**
	PWR	1 530	4 043	4 758	5 612	0.16	0.01	9.33	15.40	**57.83**	**96.84**
United States	Advanced Gen III+	1 350	3 382	3 814	4 296	0.13	0.01	9.33	12.87	**48.73**	**77.39**
NON-OECD MEMBERS											
Brazil	PWR	1 405	3 798	4 703	5 813	0.84	0.84	11.64	15.54	**65.29**	**105.29**
China	CPR-1000	1 000	1 763	1 946	2 145	0.08	0.01	9.33	7.10	**29.99**	**44.00**
	CPR-1000	1 000	1 748	1 931	2 128	0.08	0.01	9.33	7.04	**29.82**	**43.72**
	AP-1000	1 250	2 302	2 542	2 802	0.10	0.01	9.33	9.28	**36.31**	**54.61**
Russia	VVER-1150	1 070	2 933	3 238	3 574	0.00	0.00	4.00	16.74/16.94	**43.49**	**68.15**
INDUSTRY CONTRIBUTION											
EPRI	APWR. ABWR	1 400	2 970	3 319	3 714	0.12	0.01	9.33	15.80	**48.23**	**72.87**
Eurelectric	EPR-1600	1 600	4 724	5 575	6 592	0.19	0.02	9.33	11.80	**59.93**	**105.84**

*The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

6. For nuclear power plants, fuel cycle costs include front-end costs as for all other generating technologies, but also back-end costs associated with waste management. In the case of coal, mine waste management and land restoration costs are included in the fuel costs, insofar as these are required by national legislation, whereas ash management is included in O&M costs.

Table 3.7b: Coal-fired power plants: Levelised costs of electricity in US dollars per MWh

Country	Technology	Net capacity	Electrical conversion efficiency	Overnight costs [1]	Investment costs [2]		Decommissioning costs		Fuel costs	Carbon costs	O&M costs [3]	LCOE	
					5%	10%	5%	10%				5%	10%
		MWe	%	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	USD/MWh	
Belgium	Black SC	750	45%	2 539	2 761	3 000	0.10	0.02	28.80	23.59	8.73	**82.32**	**100.43**
	Black SC	1 100	45%	2 534	2 756	2 994	0.10	0.02	28.80	23.59	8.39	**81.94**	**100.01**
Czech Rep.	Brown PCC	600	43%	3 485	3 989	4 561	0.14	0.03	18.39	25.11	8.53	**84.54**	**114.12**
	Brown FBC	300	42%	3 485	3 995	4 572	0.14	0.03	18.83	25.71	8.86	**85.94**	**115.64**
	Brown IGCC	400	45%	4 671	5 360	6 146	0.18	0.04	17.57	23.40	10.35	**93.53**	**133.24**
	Brown FBC w/Biomass	300	42%	3 690	4 225	4 830	0.15	0.03	27.11	23.13	9.15	**93.71**	**125.01**
	Brown PCC w/CC(S)	510	38%	5 812	6 565	7 417	0.22	0.05	20.81	1.41	13.43	**88.69**	**136.12**
	Brown FBC w/CC(S)	255	37%	6 076	6 872	7 768	0.23	0.05	21.37	1.44	14.69	**92.89**	**142.57**
	Brown IGCC w/CC(S)	360	43%	6 268	7 148	8 148	0.23	0.05	18.52	1.17	12.26	**88.29**	**140.64**
	Br FBC w/BioM and CC(S)	255	37%	6 076	6 872	7 768	0.23	0.05	30.78	1.44	14.98	**102.59**	**152.27**
Germany	Black PCC	800	46%	1 904	2 131	2 381	0.08	0.02	28.17	22.07	12.67	**79.26**	**94.10**
	Black PCC w/CC(S)	740	38%	3 223	3 566	3 946	0.12	0.03	34.56	3.25	20.11	**85.28**	**109.61**
	Brown PCC	1 050	45%	2 197	2 459	2 747	0.09	0.02	11.27	26.12	14.04	**70.29**	**87.41**
	Brown PCC w/CC(S)	970	37%	3 516	3 890	4 304	0.13	0.03	13.70	3.81	20.70	**68.06**	**94.60**
Japan	Black	800	41%	2 719	2 935	3 166	0.11	0.02	31.61	23.88	10.06	**88.08**	**107.03**
Korea	Black PCC	767	41%	895	978	1 065	0.04	0.01	31.53	24.04	4.25	**68.41**	**74.25**
	Black PCC	961	42%	807	881	960	0.03	0.01	30.78	23.50	3.84	**65.86**	**71.12**
Mexico	Black PCC	1 312	40%	1 961	2 316	2 722	0.08	0.02	26.71	23.40	6.51	**74.39**	**92.27**
Netherlands	Black USC PCC	780	46%	2 171	2 389	2 756	0.09	0.02	28.75	22.23	3.97	**73.29**	**91.06**
Slovak Rep.	Brown SC FBC	300	40%	2 762	3 092	3 462	0.11	0.02	60.16	27.27	8.86	**120.01**	**141.64**
United States	Black PCC	600	39%	2 108	2 310	2 526	0.08	0.02	19.60	26.40	8.76	**72.49**	**87.85**
	Black IGCC	550	39%	2 433	2 666	2 916	0.10	0.02	19.63	26.40	8.37	**74.87**	**92.61**
	Black IGCC w/CC(S)	380	32%	3 569	3 905	4 263	0.14	0.03	24.15	2.61	11.31	**68.04**	**93.92**
NON-OECD MEMBERS													
Brazil	Brown PCC	446	30%	1 300	1 400	1 504	0.00	0.00	15.39	0.00	37.89/43.93	**63.98**	**79.02**
China	Black USC PCC	932	46%	656	689	723	0.03	0.01	23.06	0.00	1.64	**29.99**	**34.17**
	Black SC	1 119	46%	602	632	663	0.03	0.01	23.06	0.00	1.51	**29.42**	**33.26**
	Black SC	559	46%	672	705	740	0.03	0.01	23.06	0.00	1.68	**30.16**	**34.43**
Russia	Black USC PCC	627	47%	2 362	2 496	2 637	0.00	0.00	20.41	0.00	10.96	**50.44**	**65.91**
	Black USC PCC w/CC(S)	541	37%	4 864	5 123	5 396	0.00	0.00	26.10	0.00	21.58	**86.82**	**118.34**
	Black SC PCC	314	42%	2 198	2 323	2 454	0.00	0.00	22.83	0.00	10.20	**50.77**	**65.15**
South Africa	Black SC PCC	794	39%	2 104	2 584	3 172	0.00	0.00	7.59	0.00	4.87	**32.19**	**53.99**
INDUSTRY CONTRIBUTION													
EPRI	Black SC PCC	750	41%	2 086	2 332	2 599	0.08	0.02	18.04	25.89	9.70	**71.52**	**87.68**
ESAA	Black SC AC	690	39%	2 006	2 151	2 305	0.06	0.01	9.75	25.17	4.78	**56.20**	**69.90**
	Black SC WC	698	41%	1 958	2 100	2 250	0.06	0.01	9.25	23.88	4.74	**53.97**	**67.34**
	Black USC AC	555	41%	2 173	2 331	2 498	0.06	0.01	9.25	23.88	5.69	**56.69**	**71.54**
	Black USC WC	561	43%	2 114	2 267	2 429	0.06	0.01	8.80	22.71	5.64	**54.53**	**68.97**
	Black USC AC 90% CC(S)	434	31%	3 919	4 203	4 504	0.10	0.02	12.38	3.19	11.10	**58.87**	**85.66**
	Black USC WC 90% CC(S)	439	33%	3 775	4 049	4 338	0.10	0.02	11.61	3.00	10.98	**56.62**	**82.42**
	Black IGCC w/85% CC(S)	523	37%	4 194	4 508	4 839	0.08	0.02	10.31	3.99	11.94	**60.76**	**89.62**
	Brown SC AC	686	31%	2 206	2 366	2 535	0.07	0.02	8.49	32.16	5.36	**64.15**	**79.22**
	Brown SC WC	694	33%	2 153	2 310	2 475	0.07	0.02	8.10	30.69	5.31	**61.81**	**76.52**
	Brown USC AC	552	33%	2 374	2 546	2 728	0.08	0.02	7.98	30.23	6.41	**64.15**	**80.36**
	Brown USC WC	558	35%	2 321	2 539	2 773	0.08	0.02	7.51	28.43	6.35	**61.76**	**78.63**
	Brown USC AC 90% CC(S)	416	25%	4 087	4 383	4 696	0.12	0.03	10.63	4.03	13.93	**62.19**	**90.11**
	Brown USC WC 90%CC(S)	421	27%	3 900	4 184	4 482	0.12	0.03	9.81	3.71	13.79	**59.39**	**86.03**
Eurelectric	Black Coal	760	45%	1 952	2 205	2 489	0.08	0.02	28.80	23.59	5.11	**74.43**	**90.11**
	Brown Coal	760	43%	2 102	2 375	2 680	0.09	0.02	13.63	25.37	5.51	**62.73**	**79.61**
	Black USC w/90% CC(S)	760	39%	3 464	3 897	4 380	0.14	0.03	33.23	2.72	8.66	**74.51**	**102.00**

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

Table 3.7c: Gas-fired power plants: Levelised costs of electricity in US dollars per MWh													
Country	Technology	Net capacity	Electrical conversion efficiency	Overnight costs [1]	Investment costs [2]		Decommissioning costs		Fuel costs	Carbon costs	O&M costs [3]	LCOE	
					5%	10%	5%	10%				5%	10%
		MWe	%	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	USD/MWh	
Belgium	Single Shaft CCGT	850	58%	1 249	1 366	1 493	0.09	0.03	61.12	10.54	6.33	**89.71**	**98.29**
	CCGT	400	55%	1 099	1 209	1 328	0.08	0.03	63.89	11.02	6.56	**91.86**	**99.54**
	CCGT	420	57%	1 069	1 130	1 193	0.08	0.03	61.65	10.63	4.06	**86.05**	**92.57**
	CCGT	420	57%	1 245	1 316	1 390	0.09	0.03	61.65	10.63	5.71	**89.31**	**96.90**
Czech Rep.	CCGT	430	57%	1 573	1 793	2 043	0.12	0.04	61.65	10.23	3.73	**91.92**	**104.48**
	CCGT w/CC(S)	387	54%	2 611	2 925	3 276	0.18	0.06	65.08	0.54	6.22	**98.21**	**117.90**
Germany	CCGT	800	60%	1 025	1 147	1 282	0.08	0.02	58.57	10.08	6.73	**85.23**	**92.81**
	Gas Turbine	150	38%	520	582	650	0.04	0.01	92.48	15.92	5.38	**118.77**	**122.61**
Italy	CCGT	800	55%	769	818	872	0.06	0.02	63.89	11.25	4.67	**86.85**	**91.44**
Japan	CCGT	1 600	55%	1 549	1 863	2 234	0.12	0.04	72.58	11.02	5.55	**105.14**	**119.53**
Korea	LNG CCGT	495	57%	643	678	713	0.05	0.02	69.79	10.42	4.79	**90.82**	**94.70**
	LNG CCGT	692	57%	635	669	704	0.05	0.02	69.54	10.38	4.12	**89.80**	**93.63**
Mexico	CCGT	446	49%	982	1 105	1 240	0.07	0.02	58.03	12.21	4.53/4.74	**84.26**	**91.85**
Netherlands	CCGT	870	59%	1 025	1 076	1 127	0.08	0.02	59.56	10.27	1.32	**80.40**	**86.48**
Switzerland	CCGT	395	58%	1 622	1 776	1 942	0.13	0.04	60.59	10.35	7.83	**94.04**	**105.19**
United States	CCGT	400	54%	969	1 039	1 113	0.07	0.02	49.27	14.74	3.61	**76.56**	**82.76**
	AGT	230	40%	649	668	687	0.05	0.02	66.52	14.74	4.48	**91.48**	**95.08**
	CCGT w/CC(S)	400	40%	1 928	2 065	2 207	0.13	0.04	67.01	1.47	5.69	**91.90**	**104.19**
NON-OECD MEMBERS													
Brazil	CCGT	210	48%	1 419	1 636	1 880	0.00	0.00	57.79	0.00	5.40	**83.85**	**94.84**
China	CCGT	1 358	58%	538	565	593	0.04	0.01	28.14	0.00	2.81	**35.81**	**39.01**
	CCGT	1 358	58%	583	612	642	0.05	0.01	28.14	0.00	3.04	**36.44**	**39.91**
Russia	CCGT	392	55%	1 237	1 296	1 357	0.00	0.00	39.14	0.00	7.55	**57.75**	**65.13**
INDUSTRY CONTRIBUTION													
EPRI	CCGT	798	48%	727	795	835	0.04	0.01	55.78	12.73	3.39	**78.72**	**83.25**
ESAA	CCGT AC	480	56%	1 678	1 749	1 821	0.11	0.04	41.25	9.98	3.64	**69.89**	**79.64**
	CCGT WC	490	58%	1 594	1 661	1 730	0.00	0.00	39.68	9.60	3.58	**67.03**	**76.36**
	OCGT AC	297	43%	742	761	779	0.00	0.00	52.87	12.80	7.67	**79.82**	**83.91**
Eurelectric	CCGT	388	58%	1 201	1 292	1 387	0.09	0.03	60.59	10.45	3.93	**86.08**	**93.84**

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

Table 3.7d: Renewable power plants: Levelised costs of electricity in US dollars per MWh

Country	Technology	Net capacity	Load factor	Overnight costs[1]	Investment costs[2]		Decommissioning costs		Fuel costs	O&M costs[3]	LCOE	
					5%	10%	5%	10%			5%	10%
		MWe	%	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	
Austria	Small Hydro	2	59%	4 254	4 605	4 767	0.00	0.34	0.00	4.25	**48.62**	**92.58**
Belgium	Onshore wind	6	29%	2 615	2 679	2 742	0.81	0.31	0.00	20.54	**95.65**	**136.23**
	Onshore wind	2	26%	2 461	2 522	2 581	0.84	0.33	0.00	26.03	**104.43**	**146.78**
	Offshore wind	3.6	37%	6 083	6 233	6 380	1.32	0.51	0.00	54.09	**188.21**	**260.80**
Canada	Onshore wind	99	30%	2 745	2 813	2 879	0.77	0.30	0.00	24.53/23.85	**99.42**	**139.23**
	Offshore wind	400	37%	4 498	4 715	4 937	1.02	0.39	0.00	35.50/34.55	**137.26**	**194.93**
	Solar PV (Park)	10	13%	3 374	3 457	3 538	2.18	0.84	0.00	14.98/14.49	**227.37**	**341.72**
	Solar PV (Industrial)	1	13%	4 358	4 465	4 571	2.81	1.09	0.00	13.69/13.29	**288.02**	**435.96**
	Solar PV (Commercial)	0.1	13%	6 335	6 492	6 645	4.09	1.58	0.00	11.16/10.83	**409.96**	**625.29**
	Solar PV (Residential)	0.005	13%	7 310	7 490	7 667	4.72	1.82	0.00	10.14/9.84	**470.30**	**718.83**
Czech Rep.	Onshore wind	15	25%	3 280	3 502	3 731	1.15	0.45	0.00	21.92	**145.85**	**219.18**
	Large Hydro	10	60%	19 330	21 302	23 448	0.13	0.01	0.00	6.39	**231.63**	**459.32**
	Small Hydro	5	60%	11 598	12 918	14 374	0.08	0.00	0.00	6.97	**156.05**	**299.11**
	Solar PV	1	20%	7 381	7 958	8 558	3.25	1.25	0.00	29.95	**392.88**	**611.26**
	Geothermal	5	70%	12 887	14 176	15 590	1.27	0.55	0.00	19.02	**164.78**	**269.93**
France	Onshore wind	45	27%	1 912	1 971	2 030	0.00	0.00	0.00	20.59	**90.20**	**121.57**
	Offshore wind	120	34%	3 824	3 940	4 055	0.00	0.00	0.00	32.35	**143.69**	**194.74**
	Solar PV	10	25%	5 588	5 755	5 920	1.53	0.59	0.00	80.97	**286.62**	**388.14**
	Biogas	0.5	80%	2 500	2 686	2 880	0.40	0.18	2.65	41.18	**79.67**	**95.47**
Germany	Onshore wind	3	23%	1 934	1 977	2 019	0.74	0.29	0.00	36.62	**105.81**	**142.96**
	Offshore wind	300	43%	4 893	4 982	5 070	0.91	0.35	0.00	46.26	**137.94**	**186.76**
	Solar PV (Open Space)	0.5	11%	3 267	3 340	3 411	2.71	1.05	0.00	52.85	**304.59**	**439.77**
	Solar PV (Roof)	0.002	11%	3 779	3 864	3 947	3.14	1.21	0.00	61.05	**352.31**	**508.71**
Italy	Onshore wind	50	22%	2 637	2 766	3 349	1.02	0.39	0.00	42.78	**145.50**	**229.97**
	Solar PV	6	16%	6 592	6 917	7 247	3.67	1.42	0.00	53.94	**410.36**	**615.98**
Japan	Large Hydro	19	45%	8 394	9 237	10 141	0.08	0.00	0.00	36.11	**152.88**	**281.51**
Netherlands	Onshore wind	3	25%	2 076	2 128	2 178	0.73	0.28	0.00	17.83	**85.52**	**122.04**
	Offshore wind	5	41%	5 727	5 996	6 268	1.13	0.44	0.00	10.63	**128.72**	**196.53**
	Solar PV (Industrial)	0.03	10%	5 153	5 280	5 404	4.67	1.80	0.00	35.16	**469.93**	**704.78**
	Solar PV (Residential)	0.0035	10%	6 752	6 919	7 082	6.12	2.36	0.00	57.13	**626.87**	**934.63**
	Solid BioM and BioG	11	85%	7 431	7 614	7 793	1.11	0.51	74.82	4.49	**160.50**	**197.04**
	Solid Biomass	20	85%	5 153	5 280	5 404	0.77	0.35	69.06	4.52	**129.88**	**155.21**
Sweden	Large Hydro	70	40%	3 414	3 848	4 334	0.04	0.00	0.00	15.17	**74.09**	**139.69**
	Wave	1000	35%	3 186	3 592	4 045	1.16	0.53	0.00	75.86	**168.75**	**224.15**
Switzerland	Onshore wind	6	23%	3 716	3 808	3 898	1.48	0.57	0.00	30.55	**162.90**	**234.32**
	Small Hydro	0.3	50%	4 001	4 498	5 052	0.67	0.03	0.00	59.73	**111.53**	**169.79**
United States	Onshore wind	150	41%	1 973	2 041	2 109	0.42	0.16	0.00	8.63	**48.39**	**70.47**
	Offshore wind	300	43%	3 953	4 169	4 394	0.75	0.29	0.00	23.63	**101.02**	**146.44**
	Solar PV	5	24%	6 182	6 365	6 545	0.11	0.04	0.00	5.71	**215.45**	**332.78**
	Solar Thermal	100	24%	5 141	5 518	5 913	1.85	0.71	0.00	27.59	**211.18**	**323.71**
	Solid Biomass	80	87%	3 830	4 185	4 564	0.14	0.03	6.73	15.66	**53.77**	**80.82**
	Biogas	30	90%	2 604	2 795	2 995	0.18	0.06	0.00	24.84	**47.53**	**63.32**
	Geothermal	50	87%	1 752	1 892	2 041	0.15	0.06	0.00	18.21	**32.48**	**46.76**
NON-OECD MEMBERS												
Brazil	Large Hydro	800	55%	1 356	1 471	1 595	0.00	0.00	0.00	2.31/2.42	**18.70**	**34.30**
	Large Hydro	300	55%	1 199	1 361	1 538	0.00	0.00	0.00	2.31/2.42	**17.41**	**33.13**
	Large Hydro	15	55%	2 408	2 529	2 651	0.00	0.00	0.00	5.20/5.80	**38.53**	**61.46**
	Biomass (Woodchip)	10	85%	2 732	3 077	3 456	0.00	0.00	19.13	26.25/31.49	**77.73**	**102.60**
China	Onshore wind	200	27%	1 223	1 253	1 283	-1.26	-0.48	0.00	15.51	**50.95**	**72.01**
	Onshore wind	50	27%	1 541	1 579	1 616	-1.58	-0.61	0.00	19.54	**64.18**	**90.70**
	Onshore wind	35	22%	1 627	1 667	1 707	-2.05	-0.79	0.00	25.33	**83.19**	**117.55**
	Onshore wind	30	20%	1 583	1 622	1 660	-2.19	-0.85	0.00	27.11	**89.02**	**125.80**
	Large Hydro	18 134	53%	1 583	1 792	2 027	0.014	0.005	0.00	9.85	**29.09**	**51.50**
	Large Hydro	6 277	34%	757	857	969	0.010	0.000	0.00	2.54	**16.87**	**33.57**
	Large Hydro	4 783	57%	896	1 014	1 147	0.007	0.0003	0.00	1.37	**11.49**	**23.28**
	Solar PV	20	21%	2 878	2 949	3 019	-3.80	-1.47	0.00	15.65	**122.86**	**186.54**
	Solar PV	10	18%	3 742	3 834	3 924	-5.76	-2.22	0.00	23.73	**186.33**	**282.92**
	Solar PV	10	21%	2 921	2 993	3 064	-3.85	-1.49	0.00	15.88	**124.70**	**189.34**
	Solar PV	10	18%	3 598	3 686	3 773	-5.54	-2.14	0.00	22.82	**179.16**	**272.04**
Russia	Onshore wind	100	32%	1 901	1 939	1 977	0.00	0.00	0.00	15.43	**63.39**	**89.60**
INDUSTRY CONTRIBUTION												
EPRI	Onshore wind	100	33%	1 845	1 975	2 108	0.49	0.19	0.00	13.35	**61.87**	**91.31**
	Solar Thermal	80	34%	4 347	4 653	4 967	1.11	0.43	0.00	26.86	**136.16**	**202.45**
ESAA	Onshore wind	149	30%	2 349	2 452	2 557	0.86	0.33	0.00	11.41	**76.89**	**113.95**
	Geothermal	500	85%	3 901	4 445	4 820	0.06	0.01	0.00	5.47	**39.48**	**68.60**
	Wave	50	56%	6 354	7 079	7 867	1.44	0.66	0.00	27.87	**171.91**	**241.87**
	Tidal	304	30%	2 611	2 823	3 207	1.10	0.51	0.00	185.02/187.50	**286.53**	**347.90**
Eurelectric	Wind Onshore	100	21%	1 952	2 000	2 047	0.86	0.33	0.00	34.91	**112.71**	**154.71**
	Offshore wind (Close)	100	37%	3 464	3 550	3 633	0.81	0.31	0.00	43.30	**120.93**	**162.89**
	Offshore wind (Far)	100	43%	4 409	4 518	4 624	0.87	0.34	0.00	53.97	**137.17**	**182.13**
	Large Hydro (River)	1 000	80%	3 603	4 174	4 834	0.02	0.00	0.00	5.02	**34.74**	**70.89**
	Large Hydro (Pump)	1 000	29%	2 703	3 130	3 625	0.04	0.002	0.00	10.55	**72.95**	**148.88**
	Solar PV	1	23%	6 006	6 154	6 299	2.37	0.92	0.00	29.30	**244.73**	**361.03**
	Solar Thermal	1	32%	5 255	5 385	5 512	1.48	0.57	0.00	36.62	**171.27**	**243.96**

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

Table 3.7e: CHP: Levelised costs of electricity in US dollars per MWh

Country	Technology	Net capacity	Overnight costs[1]	Investment costs[2]		Decommissioning costs		Fuel costs	Carbon costs	Heat credit	O&M costs[3]	LCOE	
				5%	10%	5%	10%					5%	10%
		MWe	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	
Austria	Natural Gas – CCGT	405	788	866	935	0.06	0.02	63.89	12.60	37.06	3.91	**50.79**	**56.07**
Czech Rep.	Br Coal Turbine	150	3 690	4 131	4 620	0.27	0.09	11.30	15.42	32.23	9.60	**42.12**	**108.75**
	Natural Gas – CCGT	200	1 845	2 084	2 351	0.14	0.04	54.06	9.00	12.09	4.53	**74.62**	**88.95**
	Municipal Waste Incin.	15	20 502	22 868	25 486	1.52	0.49	0.00	28.80	44.32	49.36	**247.27**	**399.94**
Germany	Black Coal	200	2 966	3 319	3 708	0.12	0.03	36.00	28.20	67.50	16.19	**38.37**	**61.48**
	Natural Gas	200	1 318	1 475	1 648	0.10	0.03	76.39	13.14	42.98	8.73	**67.97**	**77.81**
Italy	Natural Gas	850	1 332	1 562	1 712	0.02	0.01	63.89	11.02	28.15	15.50/15.08	**75.59**	**85.11**
Netherlands	Natural Gas – CCGT	250	1 348	1 402	1 731	0.10	0.03	81.72	14.27	22.39	8.79	**94.45**	**105.94**
	Natural Gas – CCGT	60	1 855	1 931	2 383	0.14	0.04	85.71	14.96	29.31	15.38	**103.34**	**119.16**
Slovak Rep.	Gas and BioM – CCGT	415	1 112	1 212	1 320	0.08	0.03	62.75	11.02	25.38	6.25	**65.06**	**72.26**
Switzerland	Natural Gas – CCGT	400	1 018	1 126	1 242	0.00	0.00	57.61	10.95	2.27	6.96	**82.85**	**90.12**
	Biogas	0.2	9 925	11 165	12 550	0.00	0.00	0.00	0.00	18.13	167.19	**251.56**	**326.68**
United States	Simple Gas Turbine	40	798	835	857	0.06	0.02	68.98	13.97	50.63	1.07	**40.58**	**45.07**
NON-OECD MEMBERS													
China	Black Coal	559	720	749	765	0.05	0.02	49.22	0.00	7.84	0.92	**48.73**	**52.70**
Russia	Black Coal PCC	103	2 791	3 096	3 432	0.00	0.00	31.24	0.00	43.72	12.95	**24.12**	**45.40**
	Gas CCGT Large	415	1 442	1 566	1 699	0.00	0.00	46.95	0.00	21.83	8.80	**47.28**	**57.00**
	Gas CCGT Small	44	1 949	2 117	2 297	0.00	0.00	49.00	0.00	19.37	11.90	**59.58**	**72.73**
	Gas Turbine Large	101	1 285	1 347	1 410	0.00	0.00	62.02	0.00	37.87	7.85	**43.49**	**51.16**
	Gas Turbine Small	24	1 615	1 692	1 772	0.00	0.00	65.87	0.00	36.51	9.86	**53.64**	**63.28**
INDUSTRY CONTRIBUTION													
EPRI	Biomass	75	2 963	3 247	3 452	0.21	0.07	16.00	3.09	22.50	12.09	**36.57**	**55.64**

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

Table 3.7f: Oil: Levelised costs of electricity in US dollars per MWh

Country	Technology	Net capacity	Load factor	Overnight costs[1]	Investment costs[2]		Decommissioning costs		Fuel costs	Carbon costs	O&M costs[3]	LCOE	
					5%	10%	5%	10%				5%	10%
		MWe	%	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	USD/MWh	
Mexico	Oil Engine (Heavy Fuel Oil)	83	85%	1 817	2 045	2 295	0.14	0.04	50.37	16.79	19.91/20.66	**104.63**	**119.03**
NON-OECD MEMBERS													
South Africa	OCGT (Diesel)	1 050	85%	461	514	571	0.00	0.00	364.59	0.00	24.26	**393.24**	**396.62**

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

Table 3.7g: Fuel cells: Levelised costs of electricity in US dollars per MWh

Country	Technology	Net capacity	Load factor	Overnight costs[1]	Investment costs[2]		Decommissioning costs		Fuel costs	Carbon costs	O&M costs[3]	LCOE	
					5%	10%	5%	10%				5%	10%
		MWe	%	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	USD/MWh	
United States	Fuel cells	10	85%	5 459	5 840	6 236	0.74	0.34	54.46	14.74	49.81	**181.17**	**213.14**

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.

Country-by-country data on electricity generating costs for different technologies

4.1 Country-by-country data on electricity generating costs (bar graphs)

Traditionally, the most eagerly anticipated output of *Projected Costs of Generating Electricity* is the intra-country comparison of the costs of different technology options for generating electricity. In the following, stacked bar graphs illustrate the total levelised cost of electricity (LCOE) as well as its main components for each country at 5 and 10% discount rates respectively.

The cost components that compose the LCOE bars are the following: investment costs,[1] operations and maintenance costs, fuel costs, carbon costs, waste management costs, decommissioning costs and a heat credit for combined-heat and power plants[2] (CHP) that is indicated as a negative cost and hence a benefit to the operator (see Chapter 2 on "Methodology, Conventions and Key Assumptions" for further details). The segments for carbon costs and the CHP heat credit are shaded rather than in solid colours. The CHP heat credit pertains to a value determined outside of the electricity generating costs in this study. In the case of carbon costs, this is to indicate that these costs reflect a specific policy decision to price carbon, which has not been taken in all the countries surveyed. As noted earlier, one of the key assumptions is that the carbon cost is fixed for the lifetime of the plant at USD 30 per tonne of CO_2.

1. Investment costs are slightly different from Tables 3.7a to 3.7g in Section 3.2, where investment costs only include overnight costs and interest during construction. Here investment costs include also the costs for refurbishment and decommissioning. The latter are too small for graphically plotting them as separate categories.

2. Consistent with the LCOE methodology, total CO_2 emissions for CHP as well as their costs have been allocated to electricity output only. While this raises carbon costs for electricity, it also raises the credit for heat output, from which no carbon costs are subtracted. The deduction from gross electricity costs is thus higher. The difference between allocating carbon cost to electricity only or splitting it between electricity and heat is thus second-order.

Figure 4.1a: Austria – levelised costs of electricity
(at 5% discount rate)

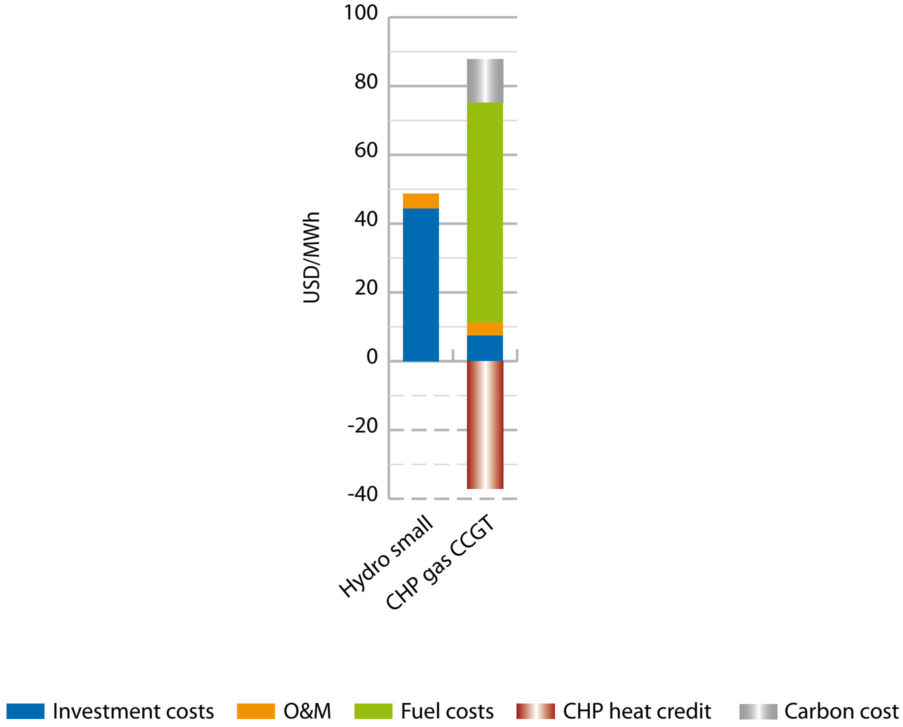


Figure 4.1b: Austria – levelised costs of electricity
(at 10% discount rate)

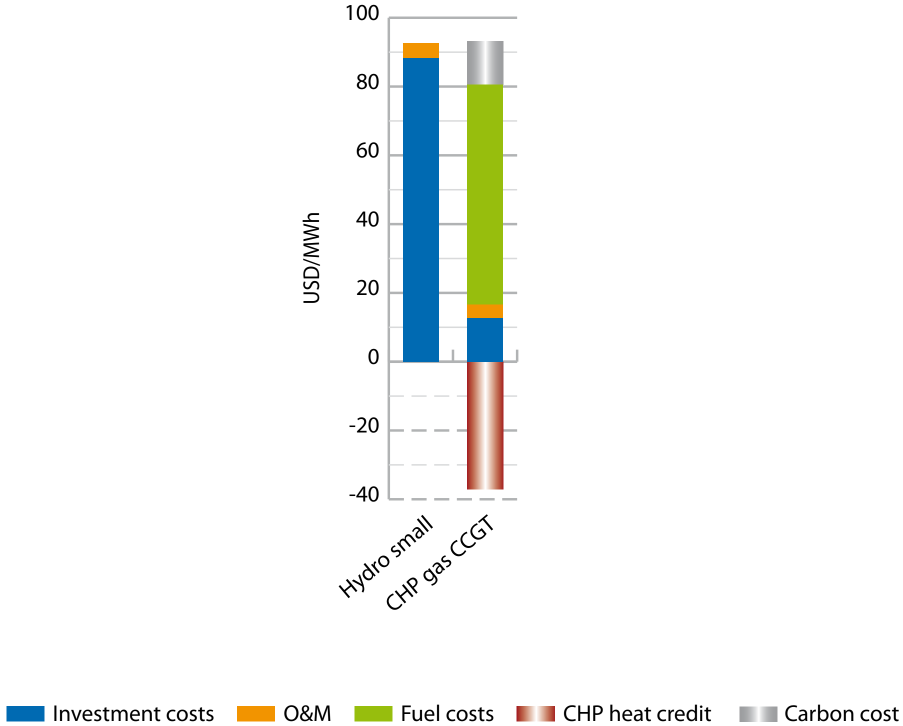


Figure 4.2a: Belgium – levelised costs of electricity
(at 5% discount rate)

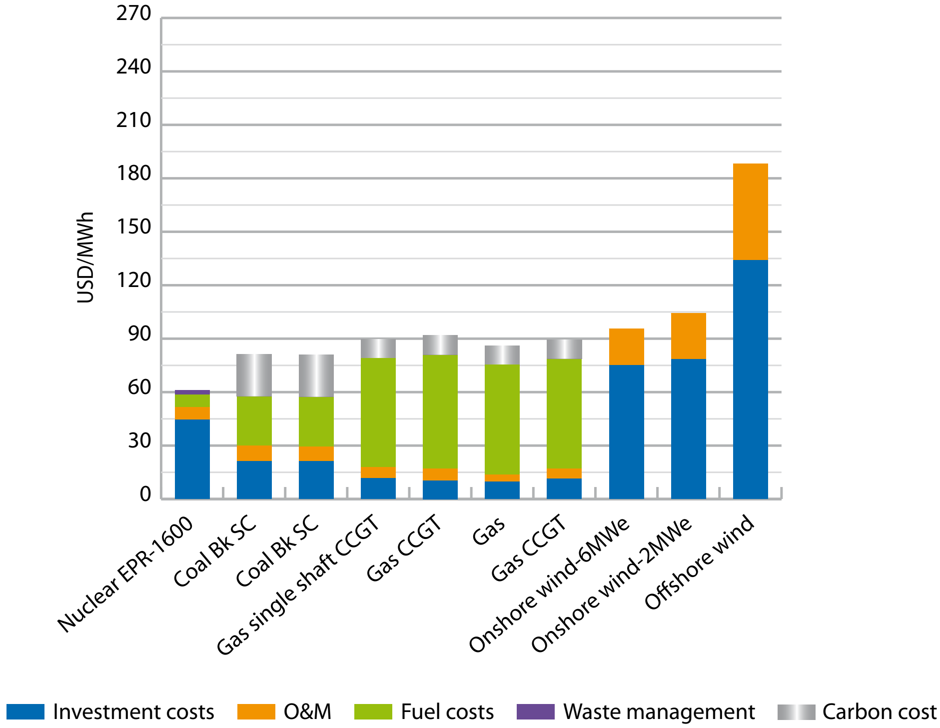


Figure 4.2b: Belgium – levelised costs of electricity
(at 10% discount rate)

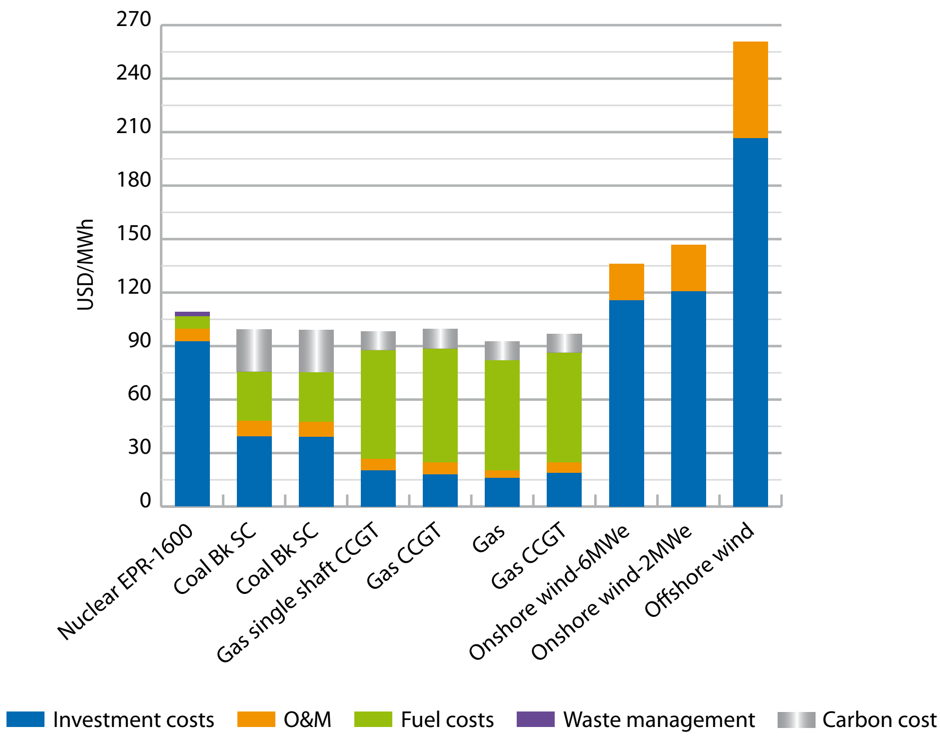


Figure 4.3a: Canada – levelised costs of electricity
(at 5% discount rate)

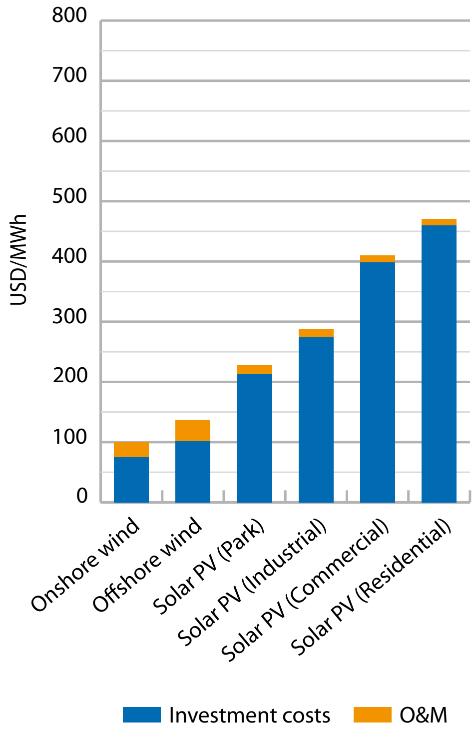


Figure 4.3b: Canada – levelised costs of electricity
(at 10% discount rate)

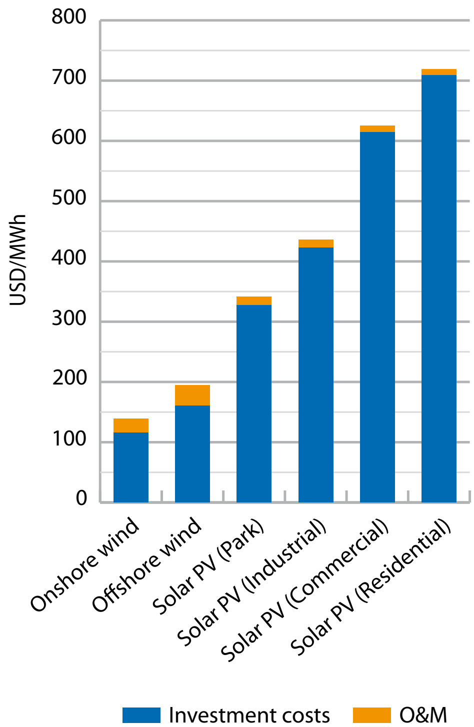


Figure 4.4a: Czech Republic – levelised costs of electricity
(at 5% discount rate)

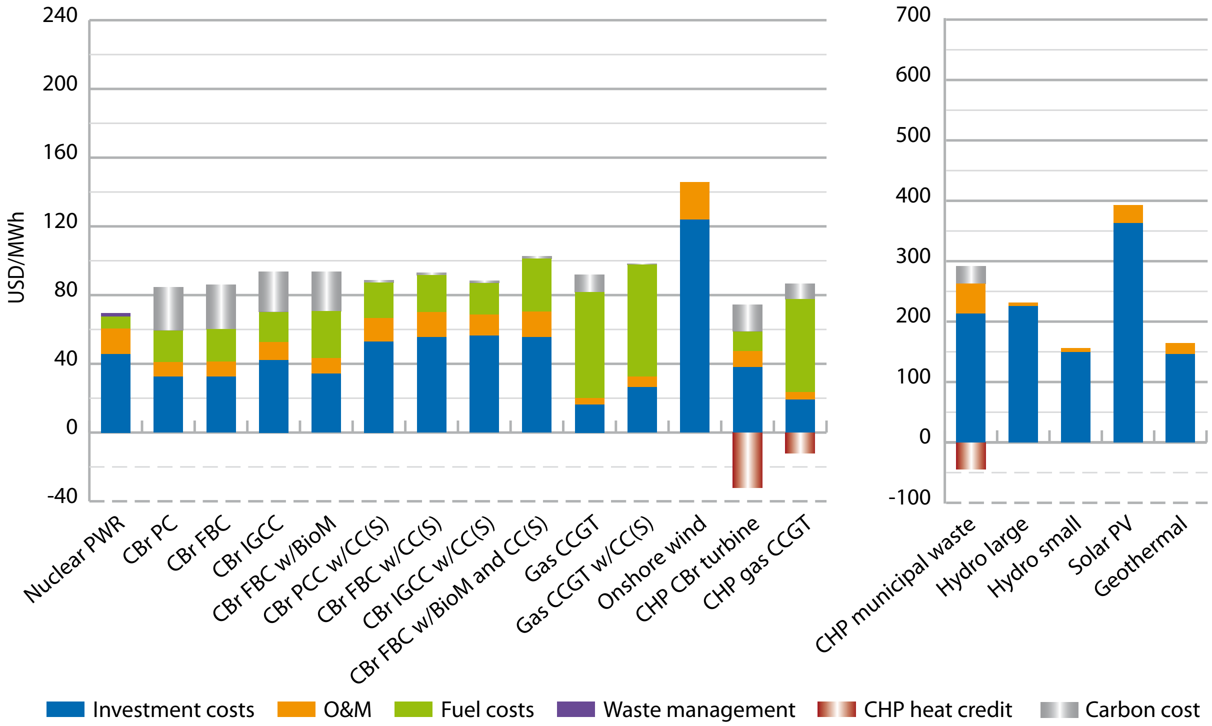


Figure 4.4b: Czech Republic – levelised costs of electricity
(at 10% discount rate)

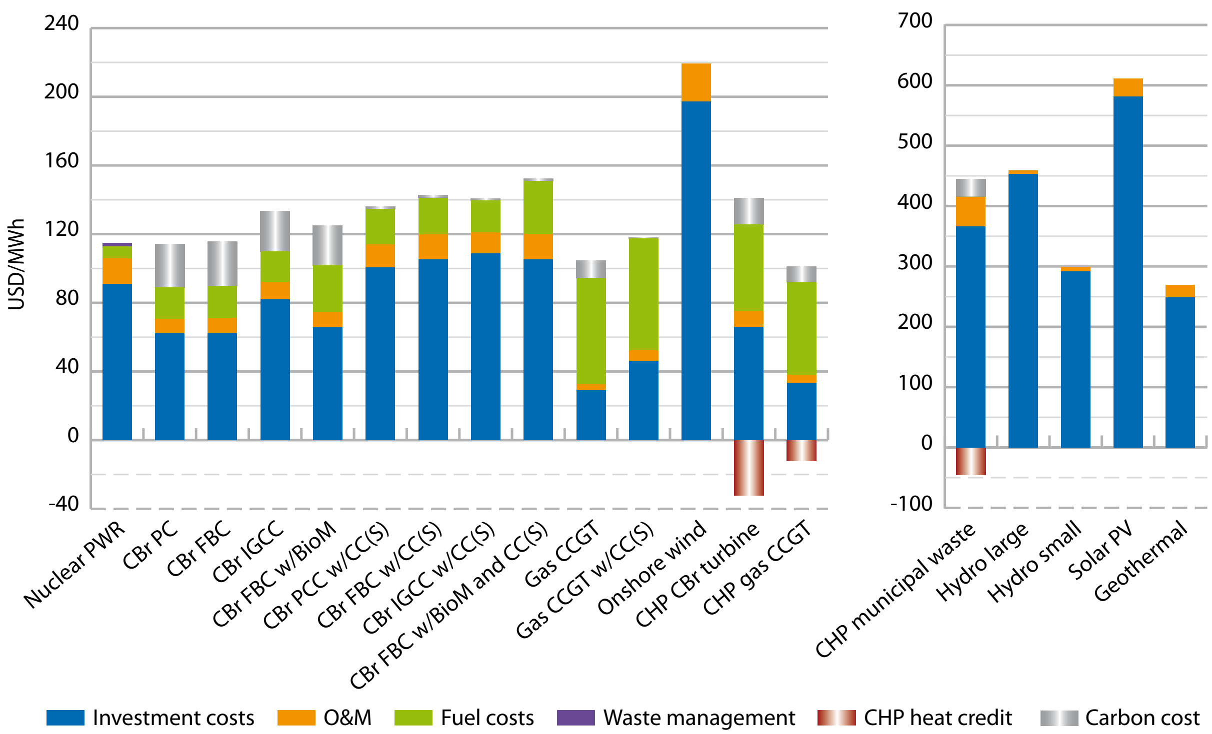


Figure 4.5a: France – levelised costs of electricity
(at 5% discount rate)

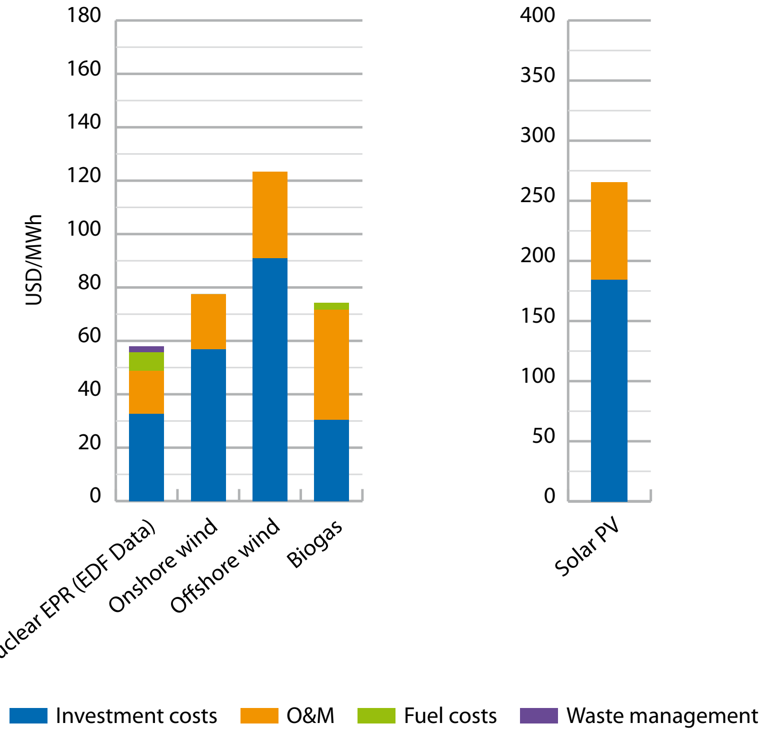


Figure 4.5b: France – levelised costs of electricity
(at 10% discount rate)

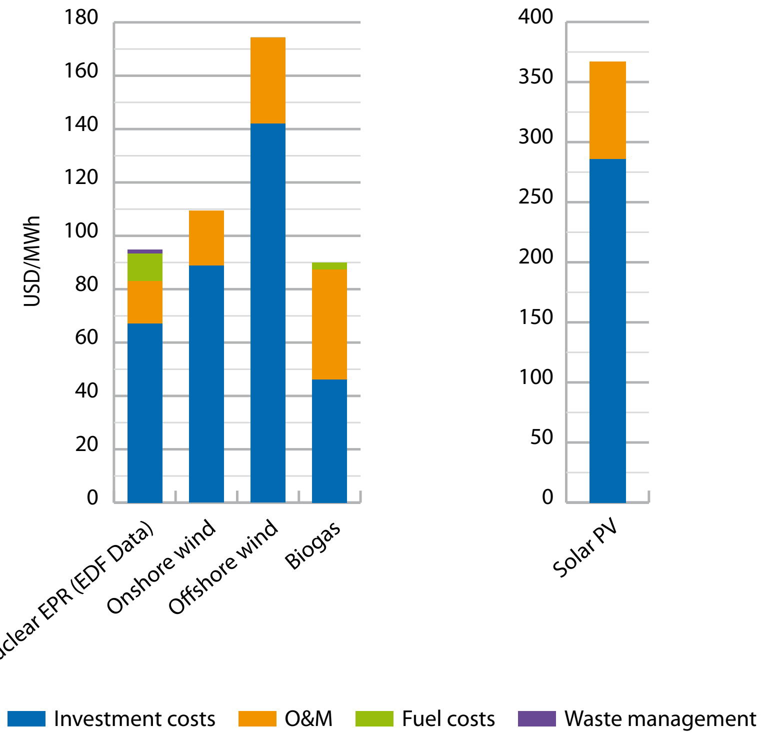


Figure 4.6a: Germany – levelised costs of electricity
(at 5% discount rate)

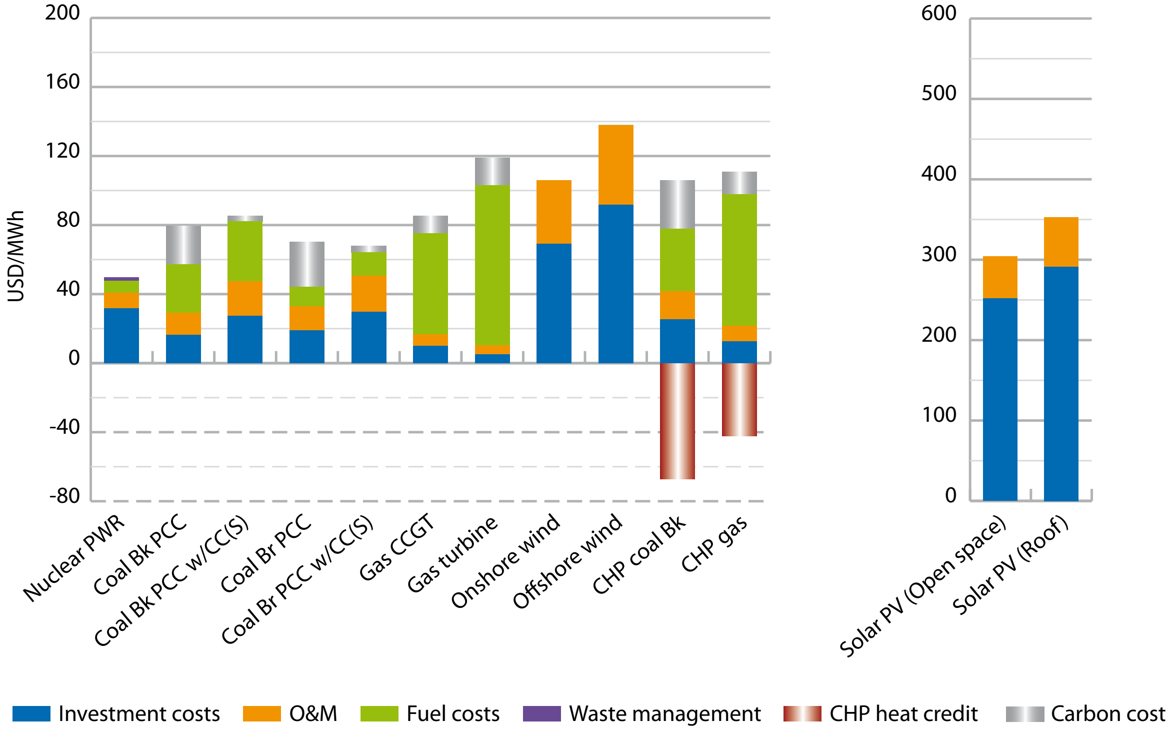


Figure 4.6b: Germany – levelised costs of electricity
(at 10% discount rate)

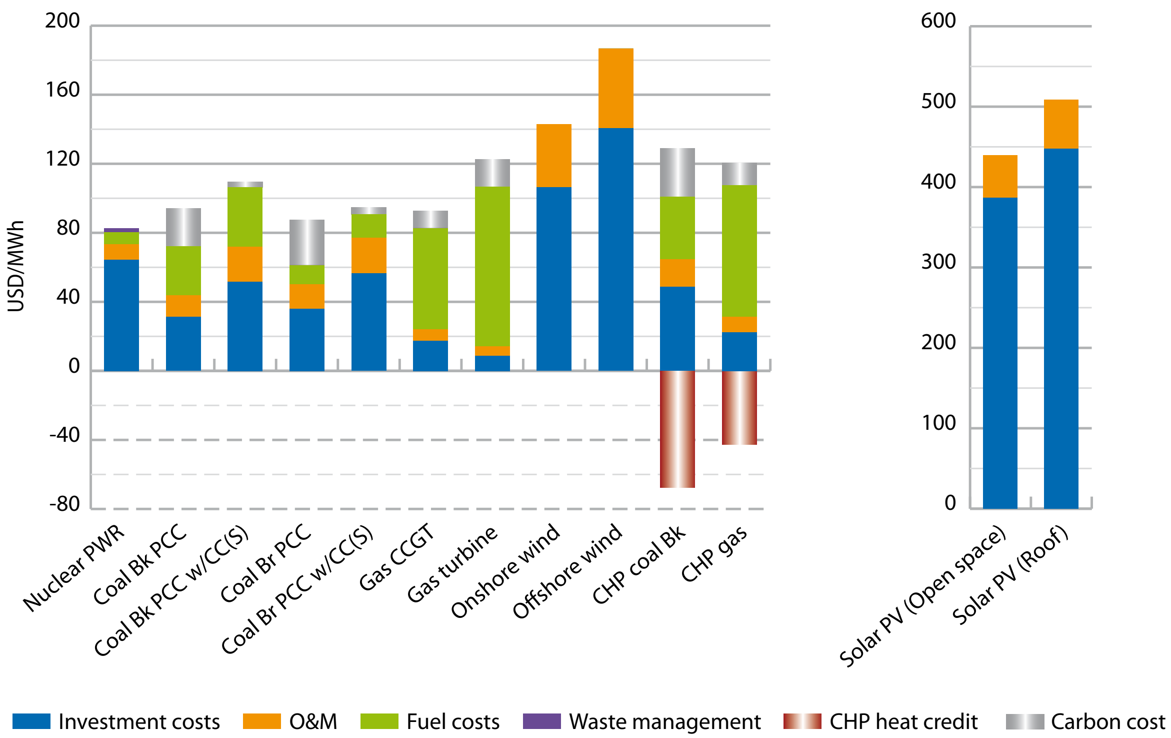


Figure 4.7a: Hungary – levelised costs of electricity
(at 5% discount rate)

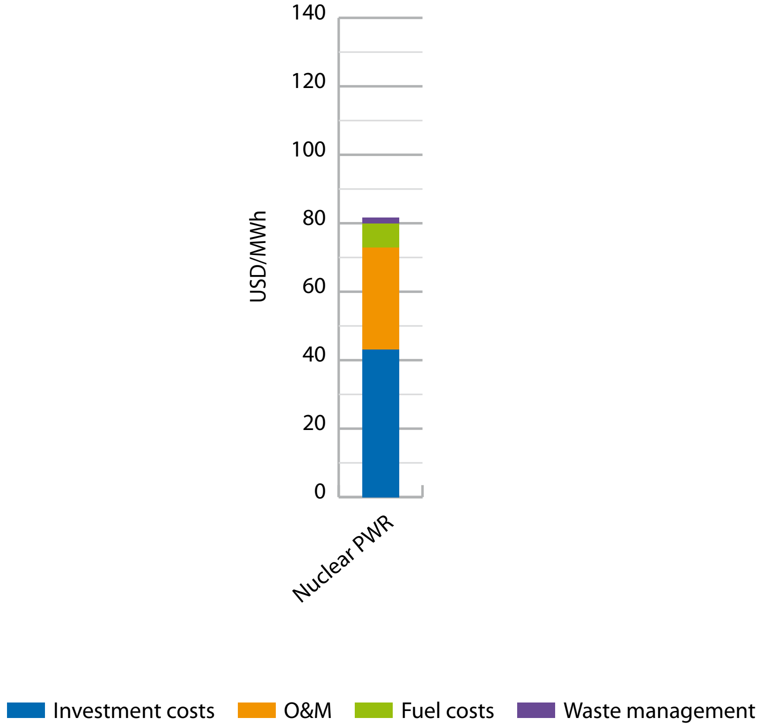


Figure 4.7b: Hungary – levelised costs of electricity
(at 10% discount rate)

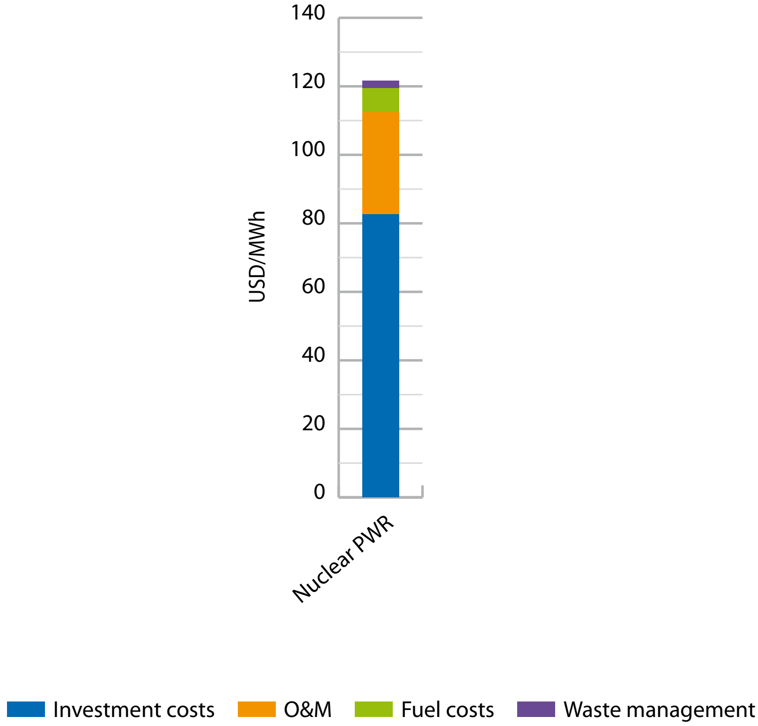


Figure 4.8a: Italy – levelised costs of electricity
(at 5% discount rate)

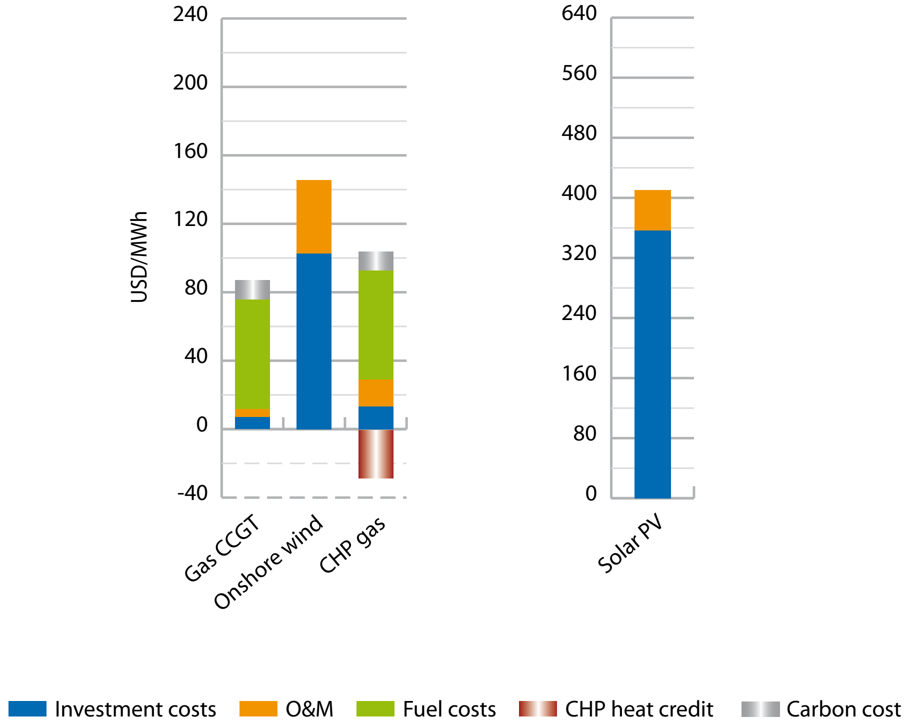


Figure 4.8b: Italy – levelised costs of electricity
(at 10% discount rate)

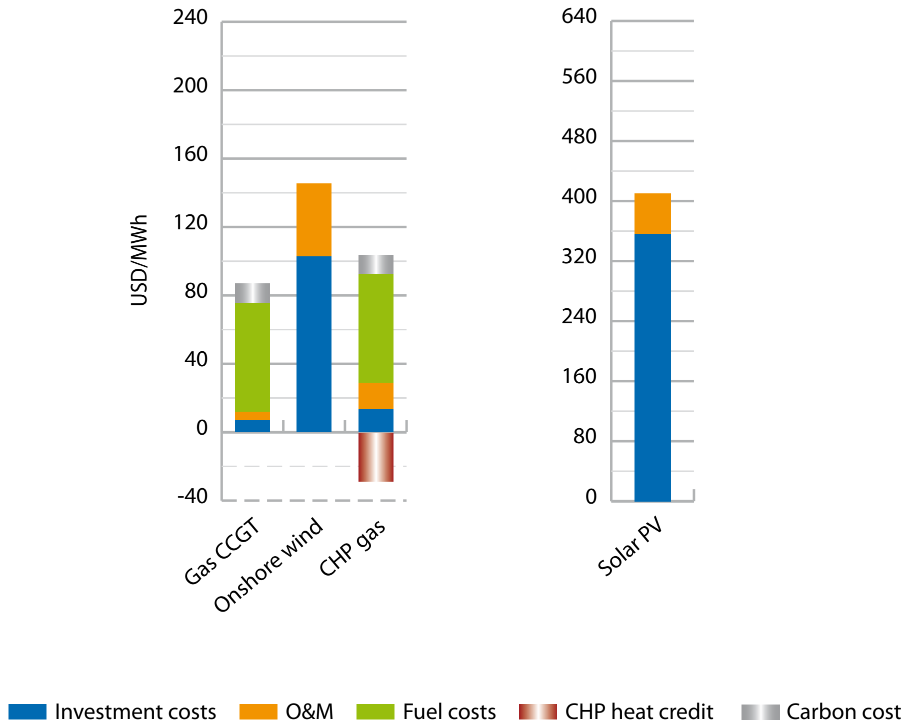


Figure 4.9a: Japan – levelised costs of electricity
(at 5% discount rate)

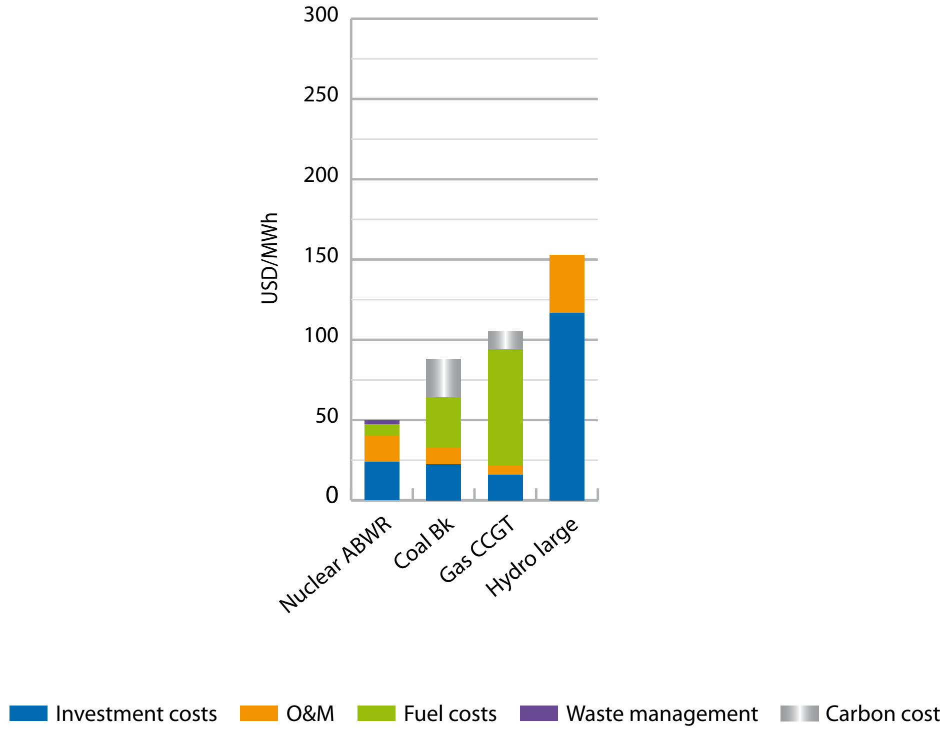


Figure 4.9b: Japan – levelised costs of electricity
(at 10% discount rate)

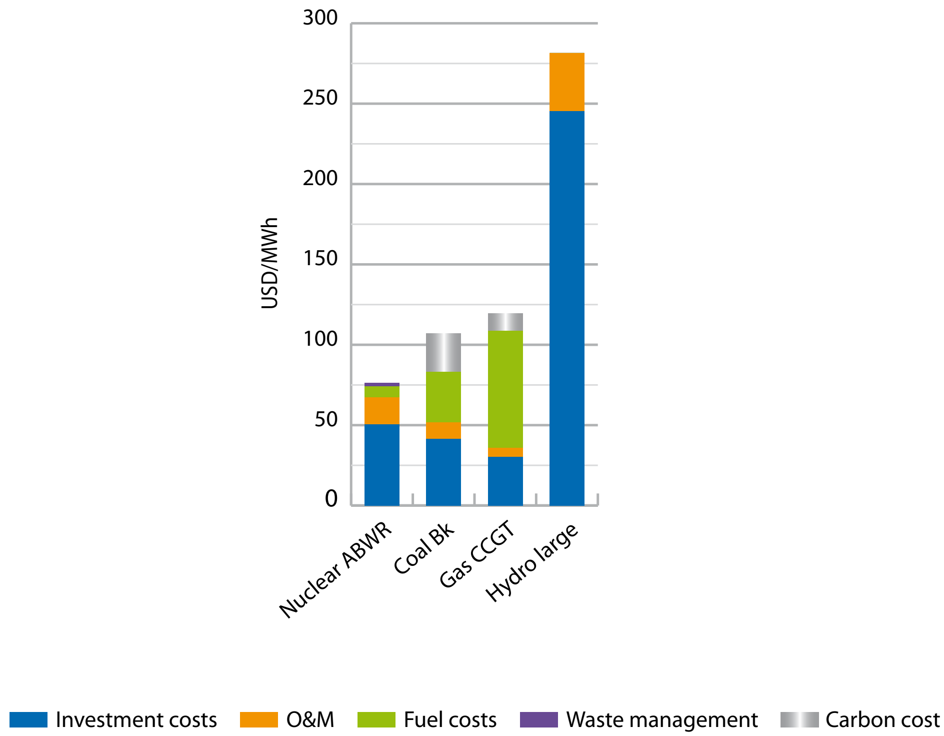


Figure 4.10a: Korea – levelised costs of electricity
(at 5% discount rate)

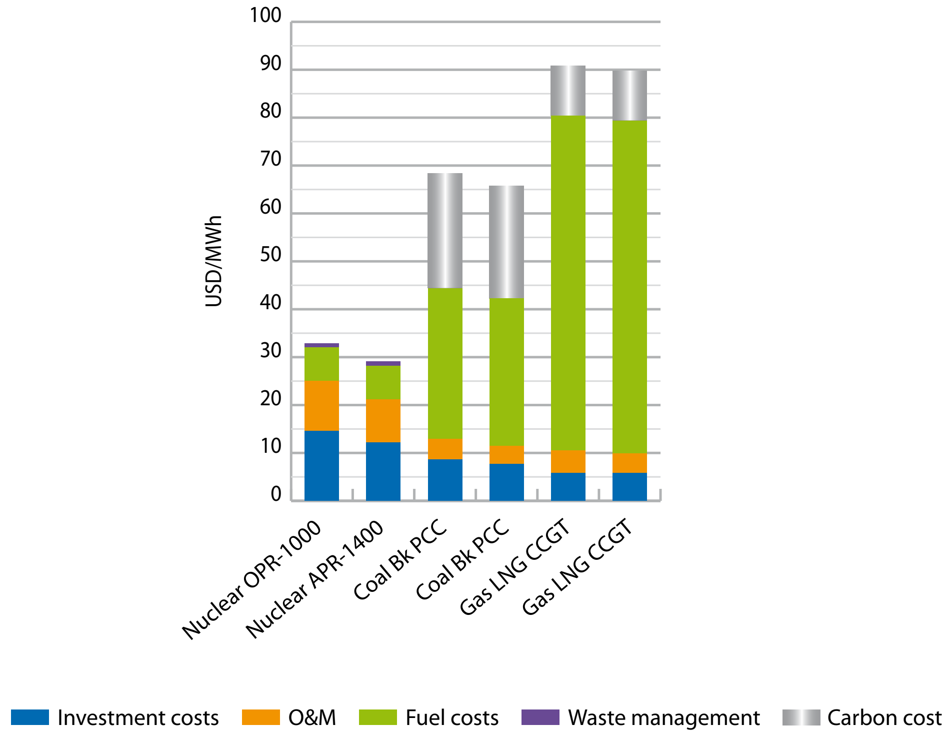


Figure 4.10b: Korea – levelised costs of electricity
(at 10% discount rate)

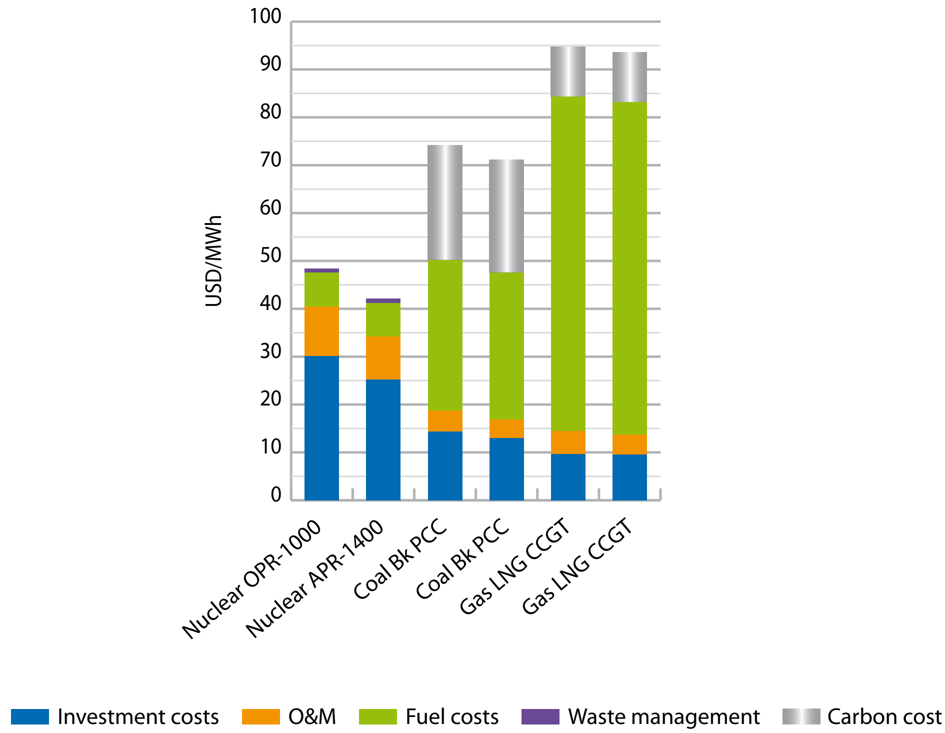


Figure 4.11a: Mexico – levelised costs of electricity
(at 5% discount rate)

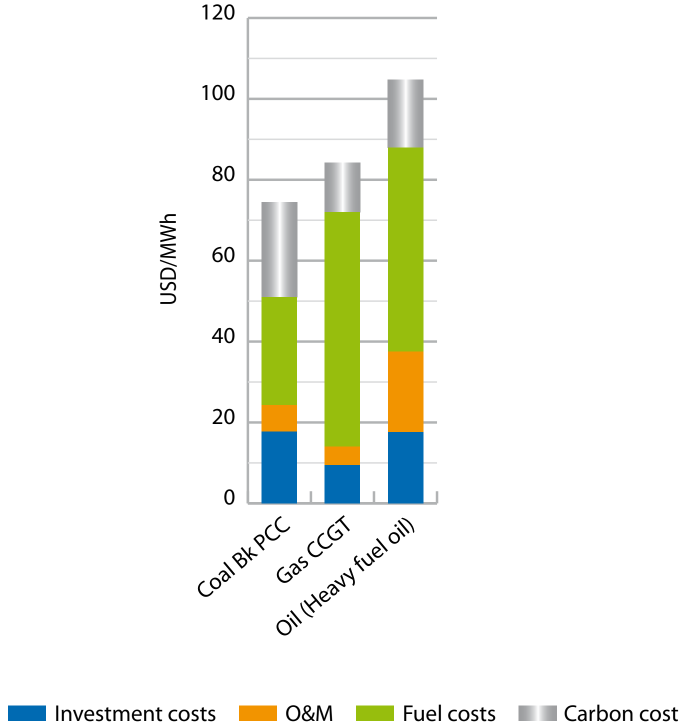


Figure 4.11b: Mexico – levelised costs of electricity
(at 10% discount rate)

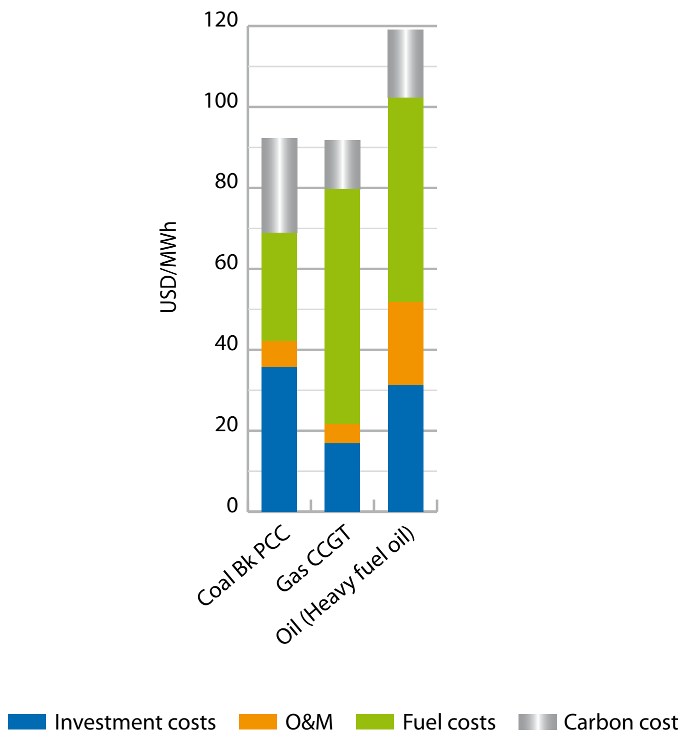


Figure 4.12a: Netherlands – levelised costs of electricity
(at 5% discount rate)

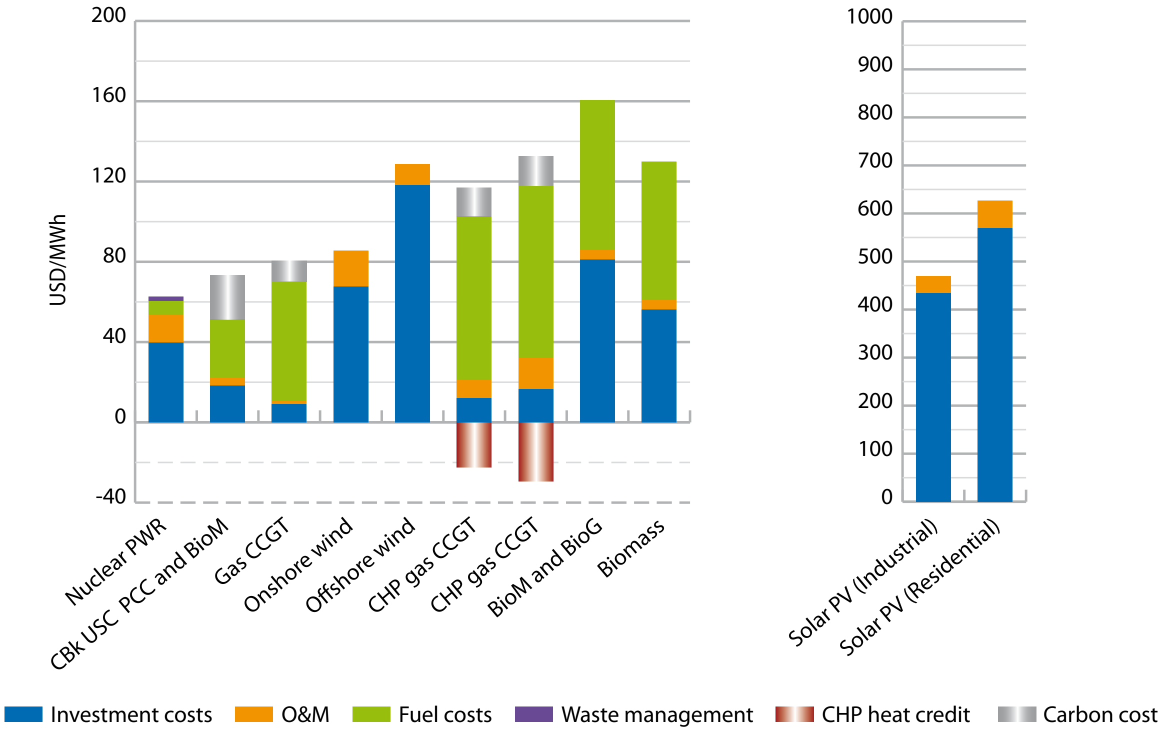


Figure 4.12b: Netherlands – levelised costs of electricity
(at 10% discount rate)

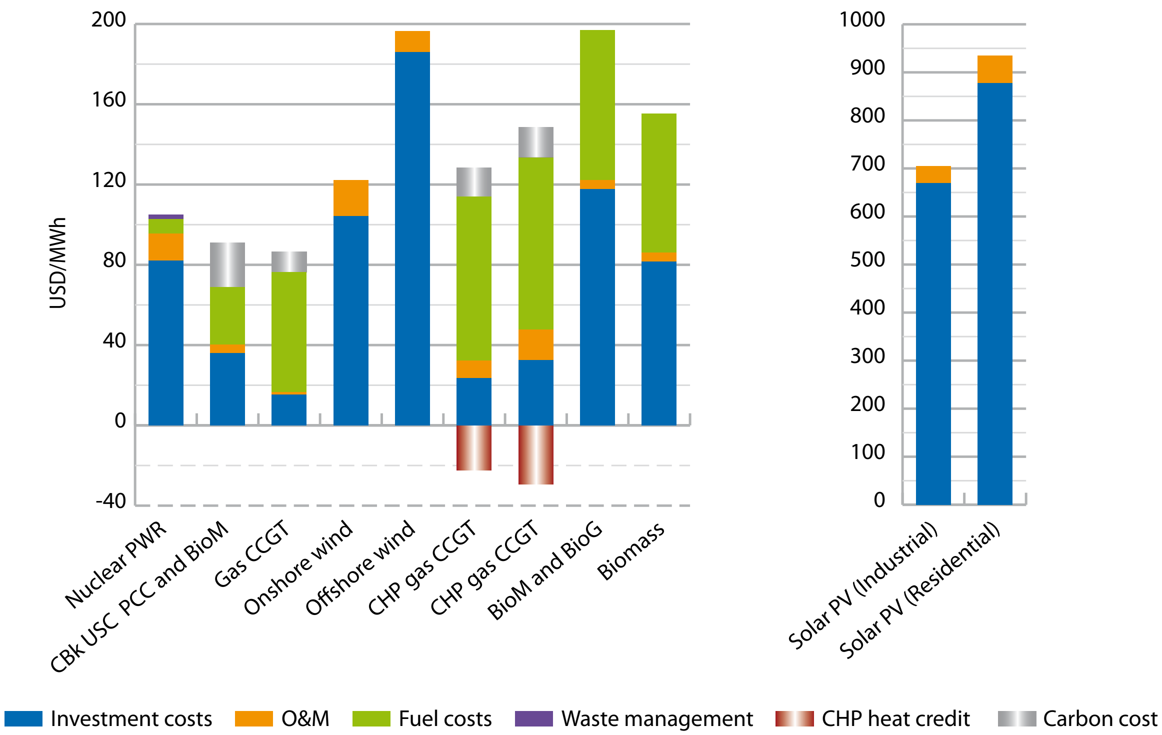


Figure 4.13a: Slovak Republic – levelised costs of electricity
(at 5% discount rate)

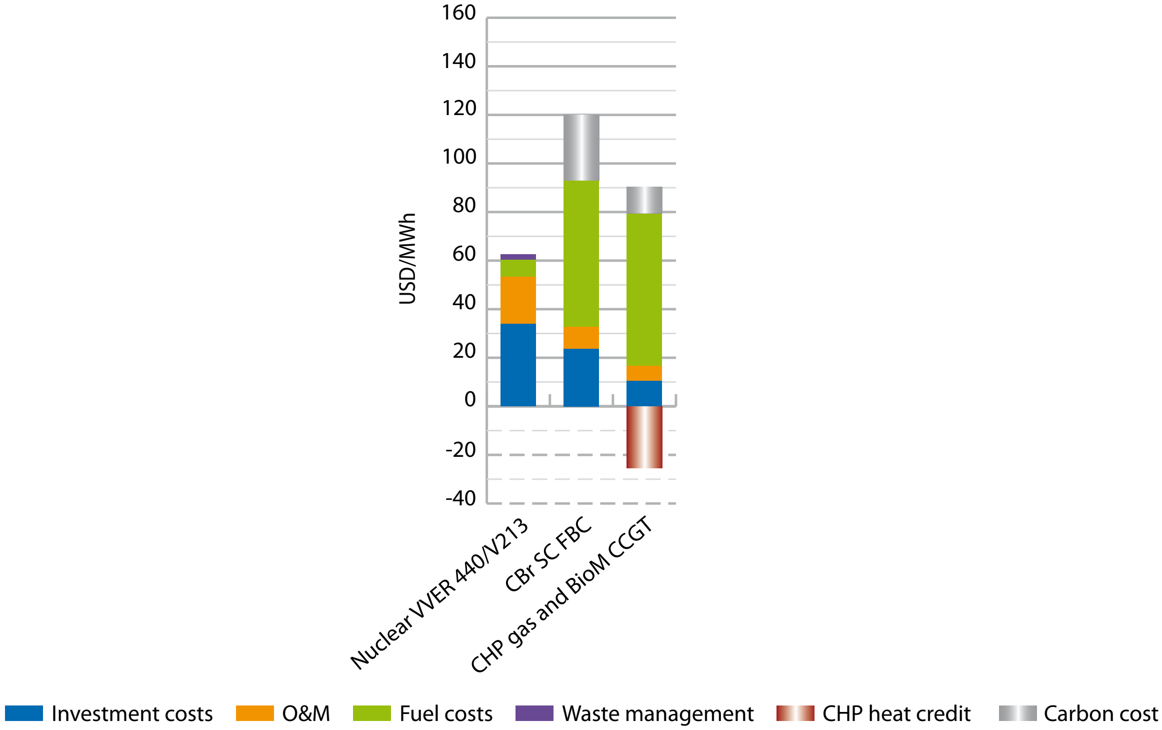


Figure 4.13b: Slovak Republic – levelised costs of electricity
(at 10% discount rate)

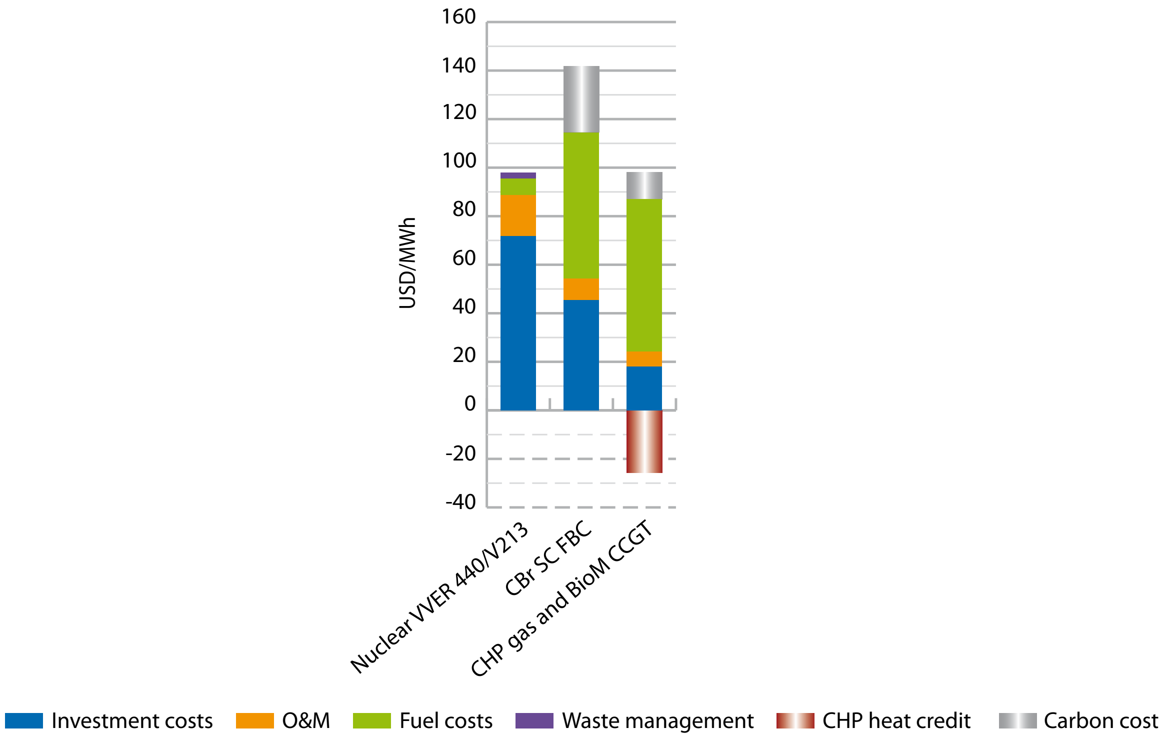


Figure 4.14a: Sweden – levelised costs of electricity
(at 5% discount rate)

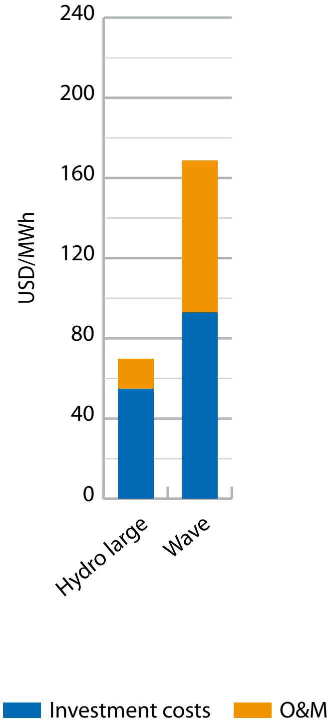


Figure 4.14b: Sweden – levelised costs of electricity
(at 10% discount rate)

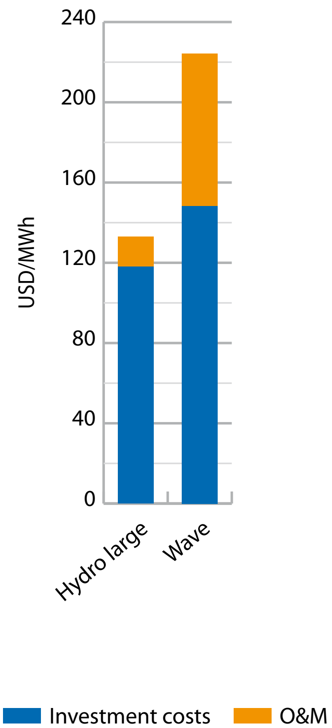


Figure 4.15a: Switzerland – levelised costs of electricity
(at 5% discount rate)

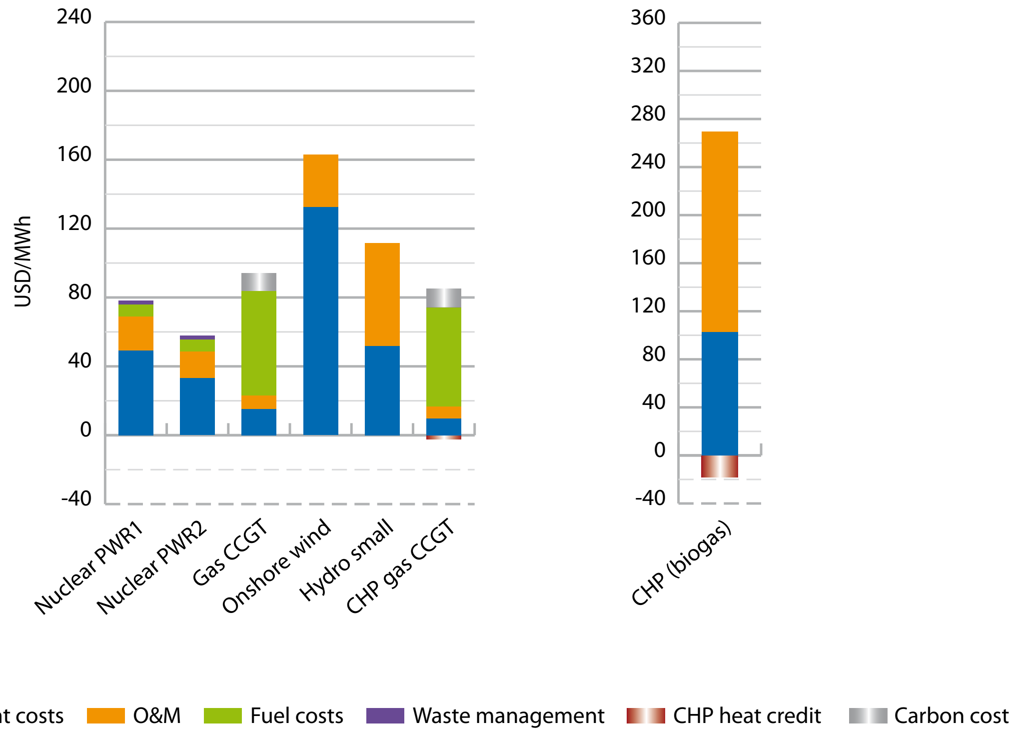


Figure 4.15b: Switzerland – levelised costs of electricity
(at 10% discount rate)

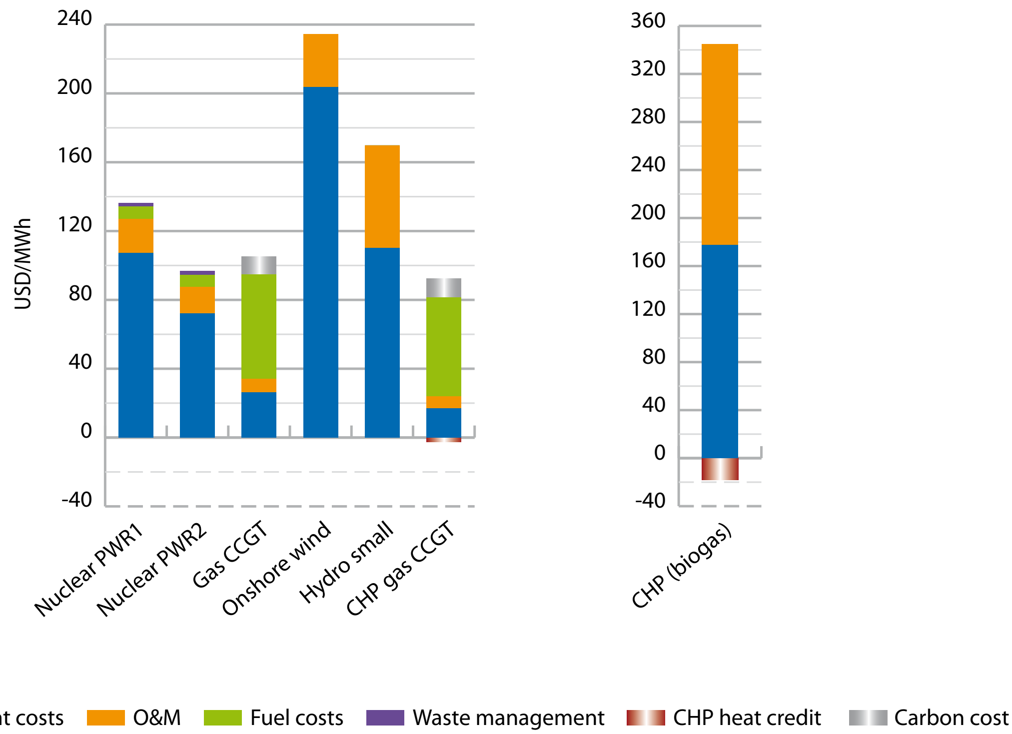


Figure 4.16a: United States – levelised costs of electricity
(at 5% discount rate)

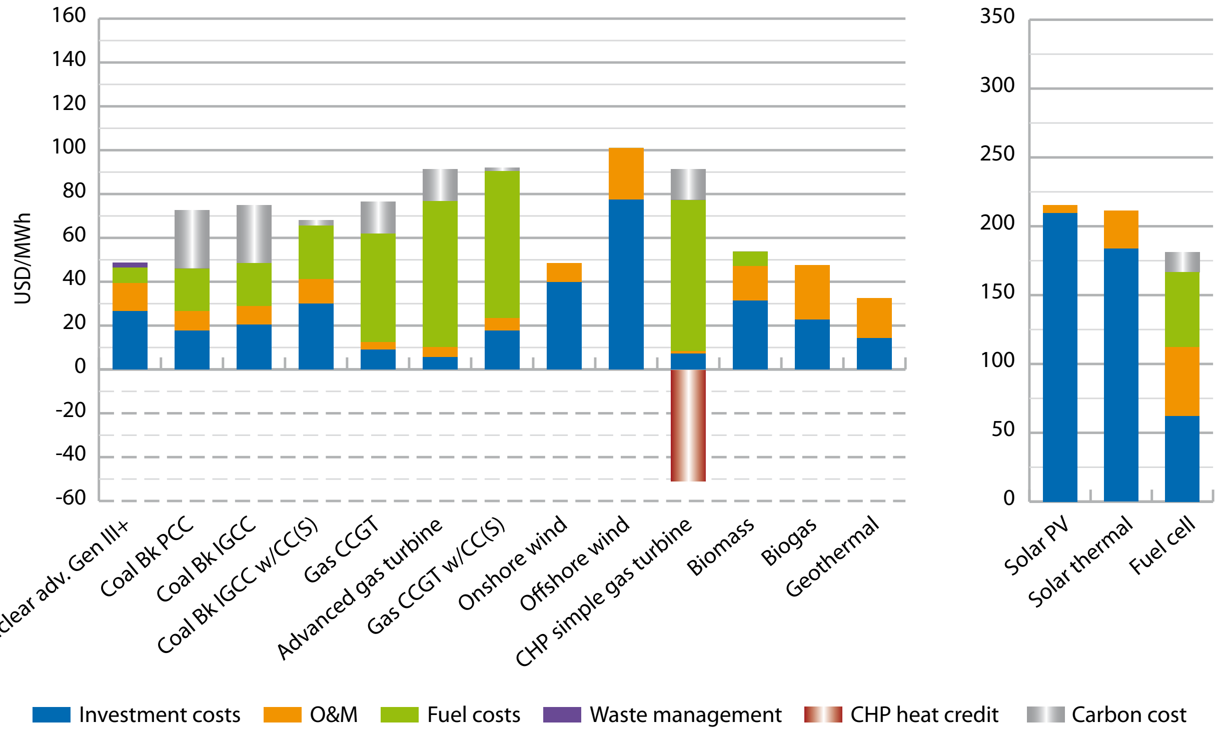


Figure 4.16b: United States – levelised costs of electricity
(at 10% discount rate)

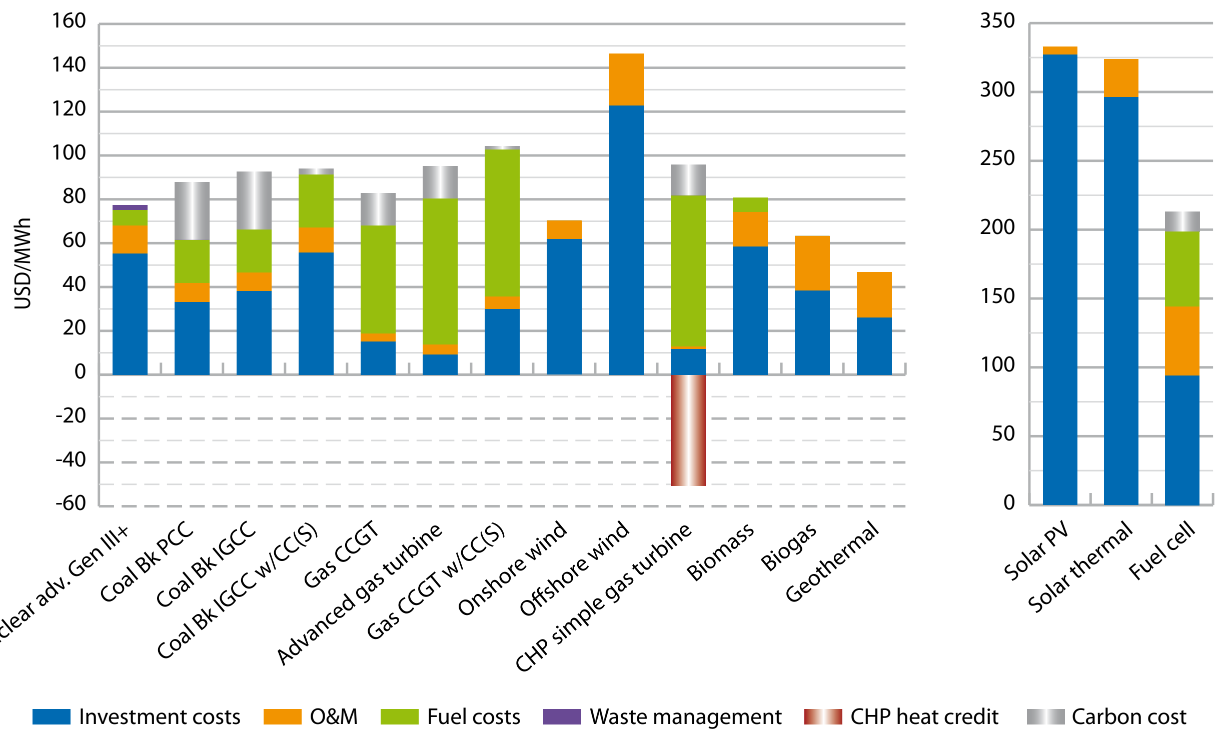


Figure 4.17a: Brazil – levelised costs of electricity
(at 5% discount rate)

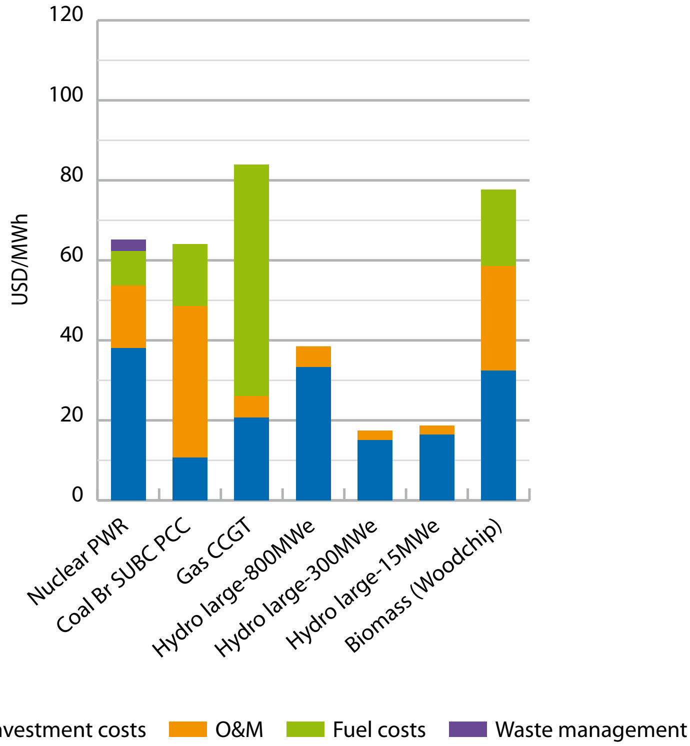


Figure 4.17b: Brazil – levelised costs of electricity
(at 10% discount rate)

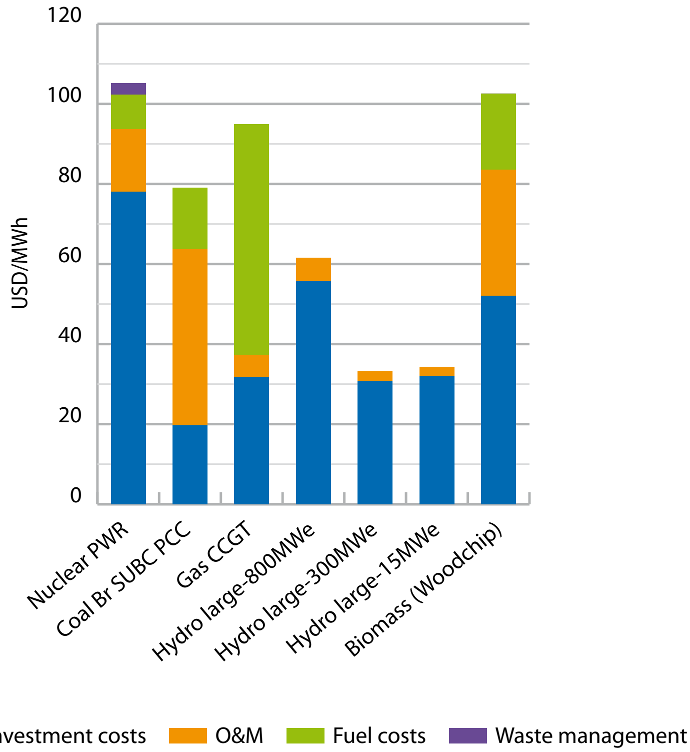


Figure 4.18a: China – levelised costs of electricity
(at 5% discount rate)

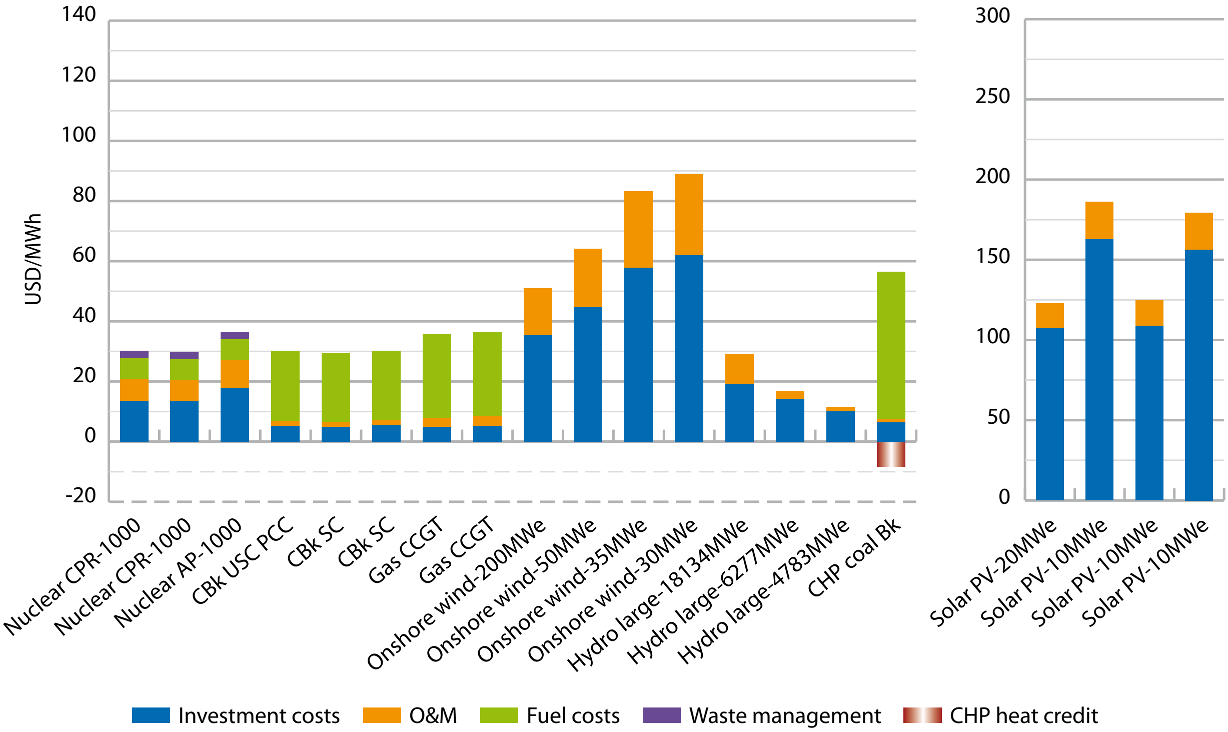


Figure 4.18b: China – levelised costs of electricity
(at 10% discount rate)

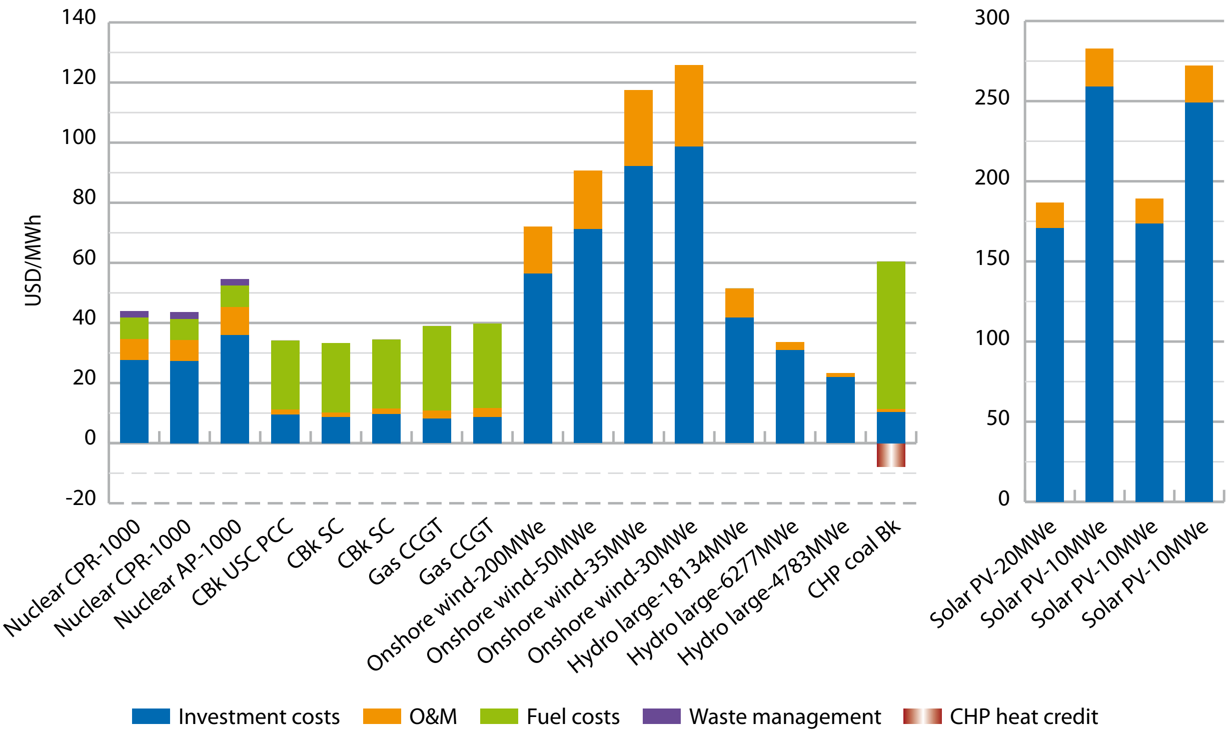


Figure 4.19a: Russia – levelised costs of electricity
(at 5% discount rate)

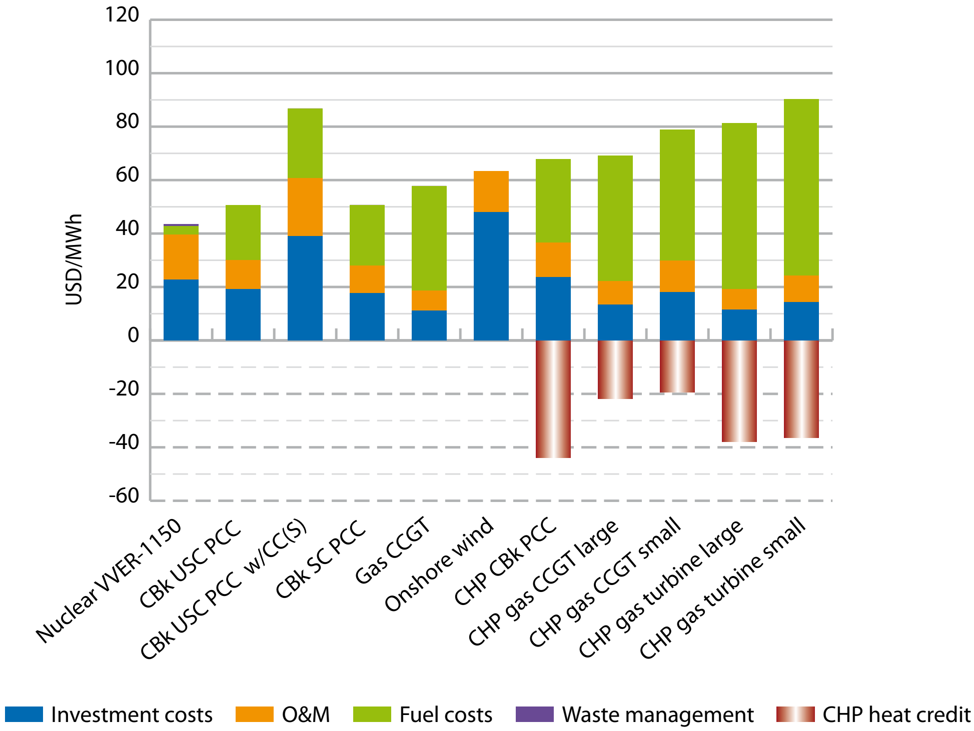


Figure 4.19b: Russia – levelised costs of electricity
(at 10% discount rate)

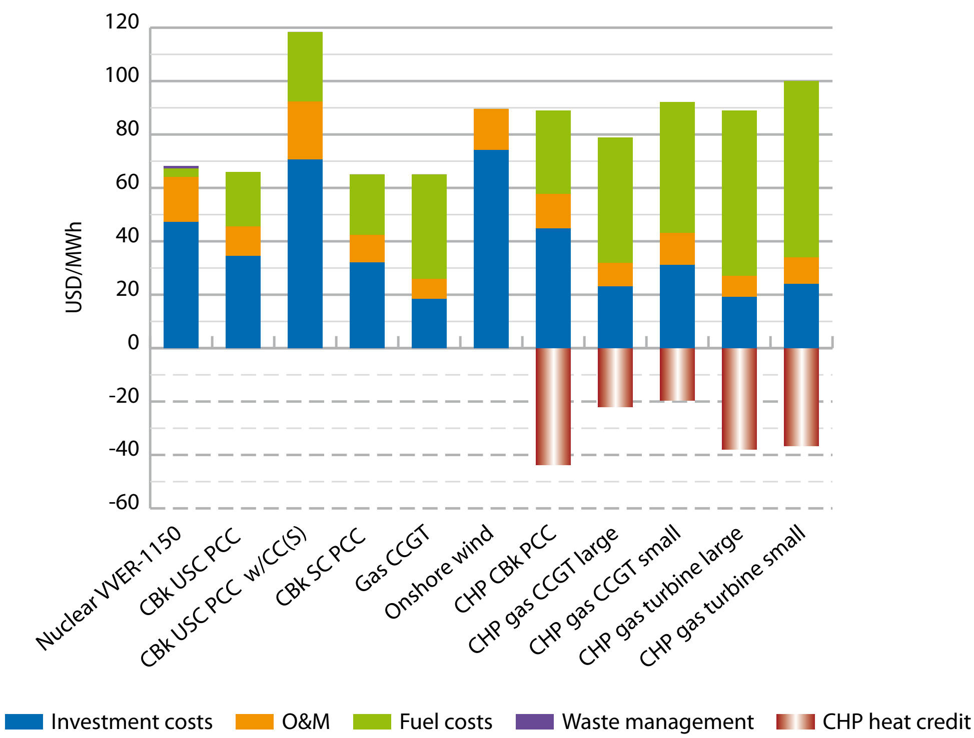


Figure 4.20a: South Africa – levelised costs of electricity
(at 5% discount rate)

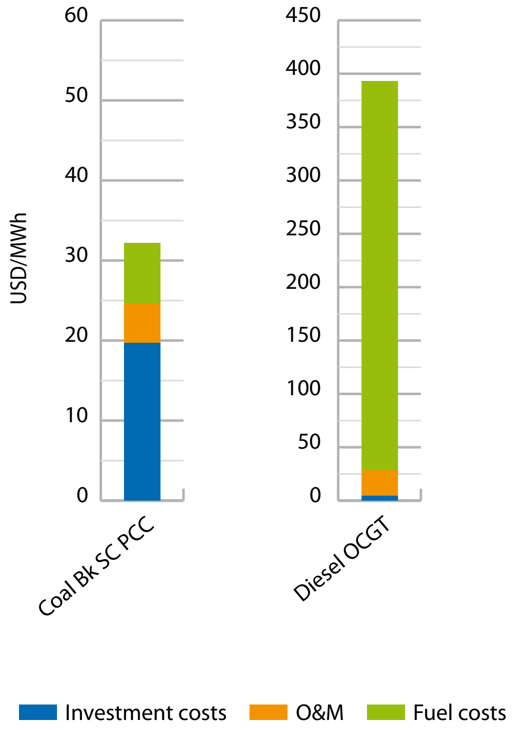


Figure 4.20b: South Africa – levelised costs of electricity
(at 10% discount rate)

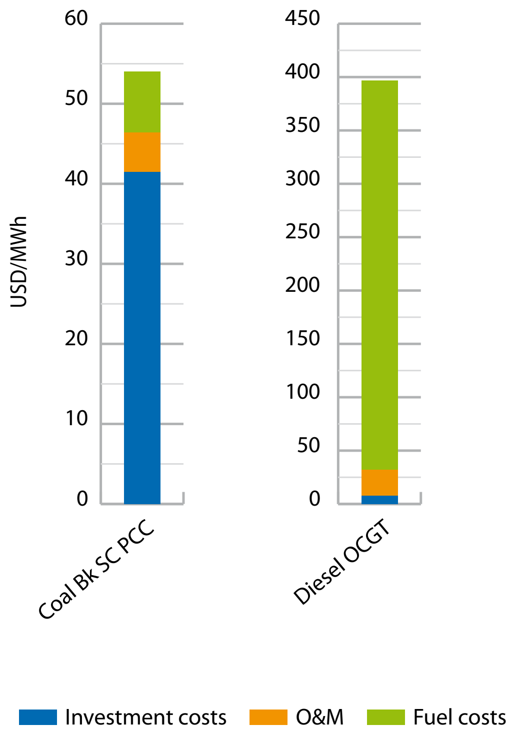


Figure 4.21a: ESAA levelised costs of electricity
(at 5% discount rate)

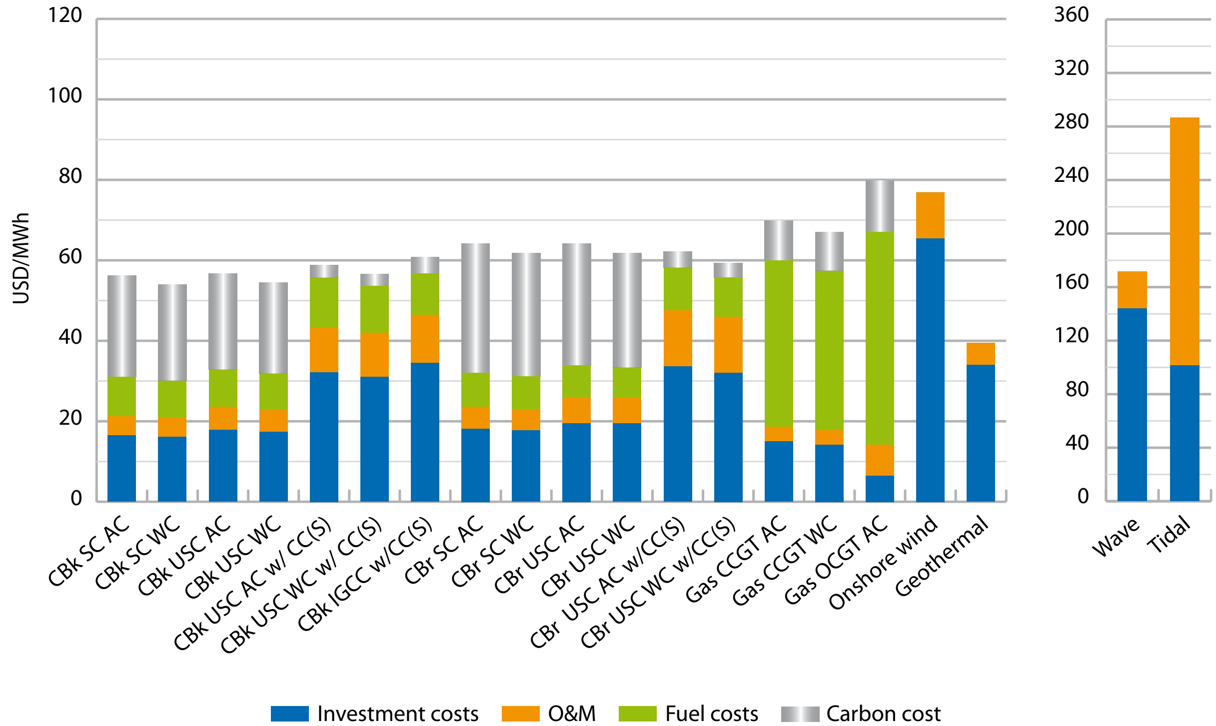


Figure 4.21b: ESAA levelised costs of electricity
(at 10% discount rate)

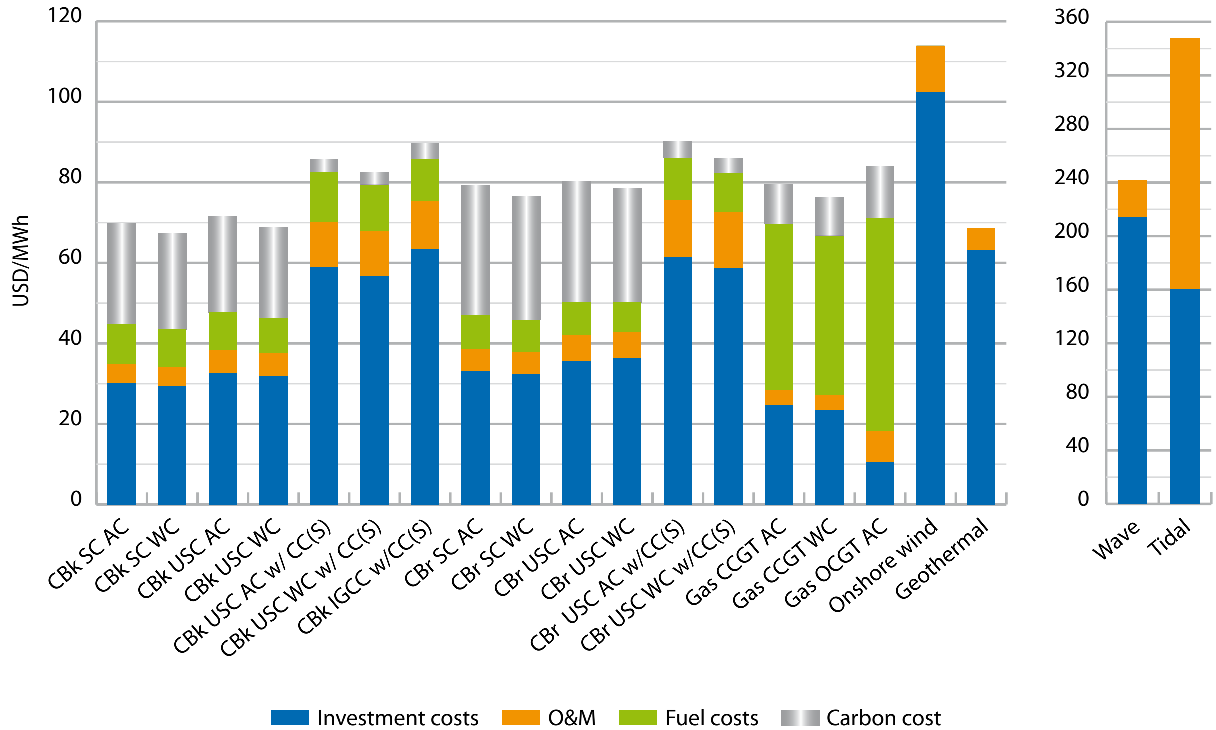


Figure 4.22a: Eurelectric/VGB levelised costs of electricity
(at 5% discount rate)

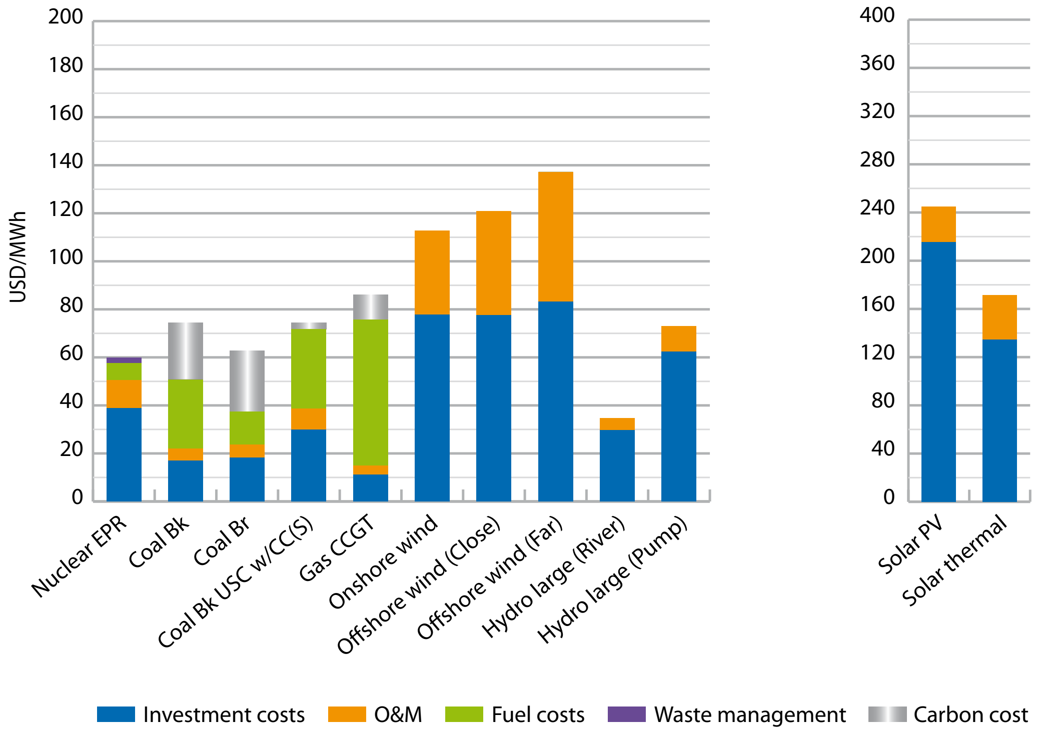


Figure 4.22b: Eurelectric/VGB levelised costs of electricity
(at 10% discount rate)

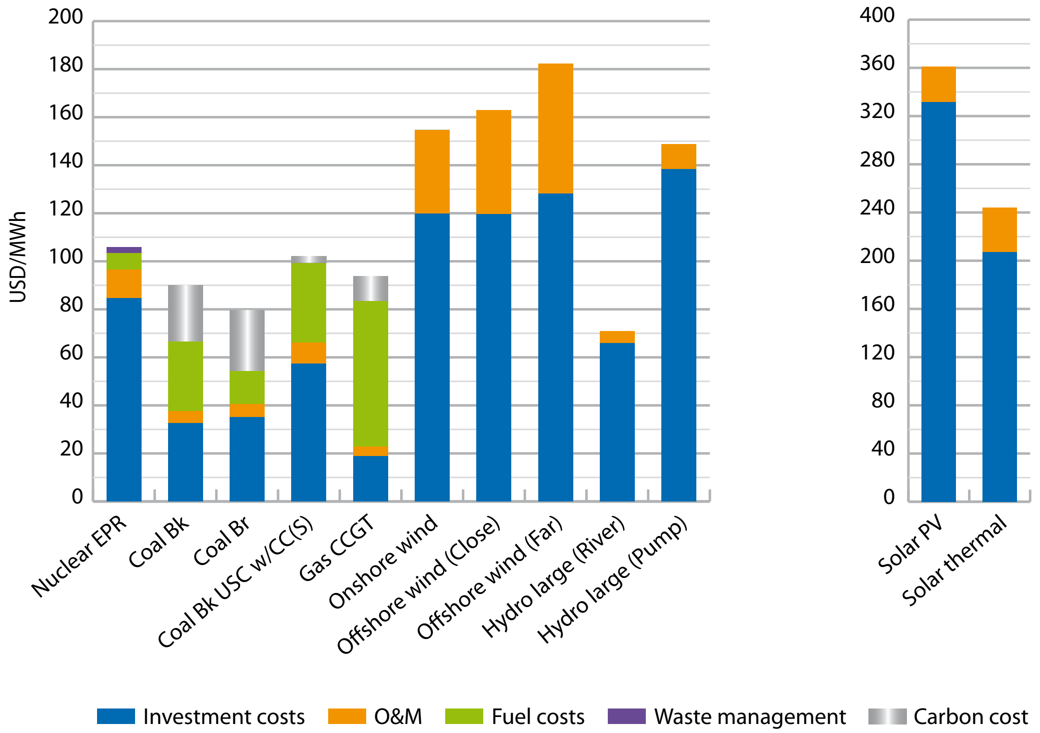


Figure 4.23a: US EPRI levelised costs of electricity
(at 5% discount rate)

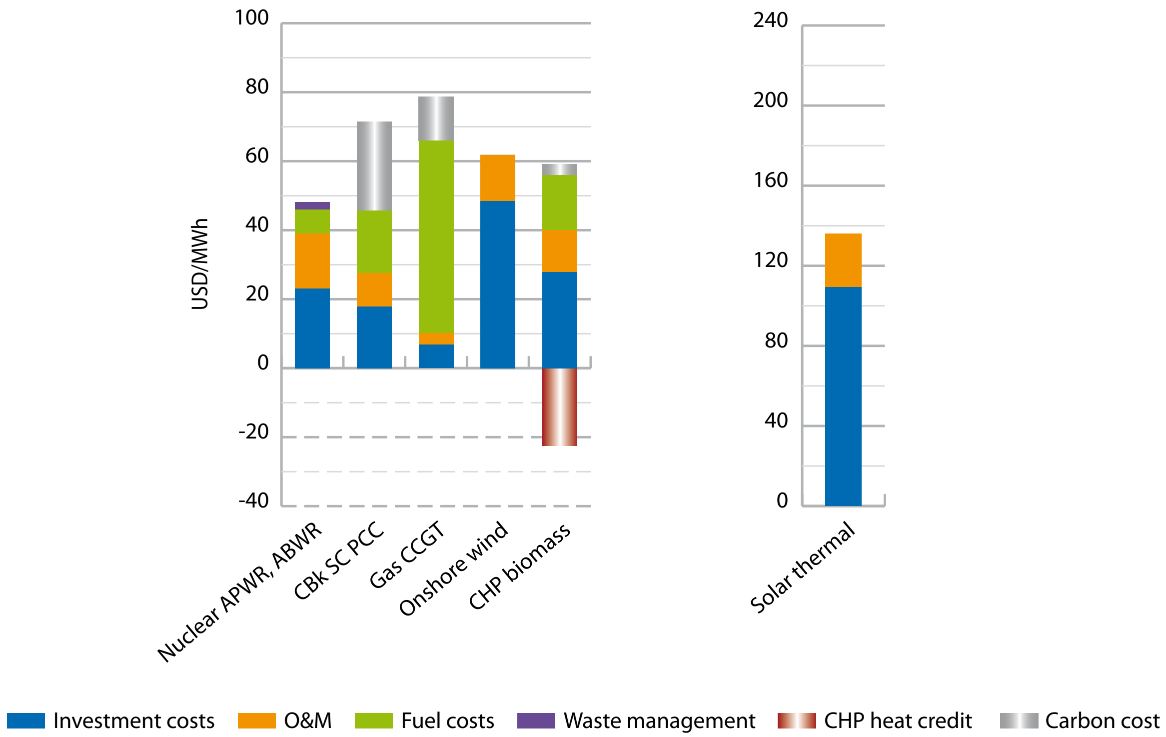
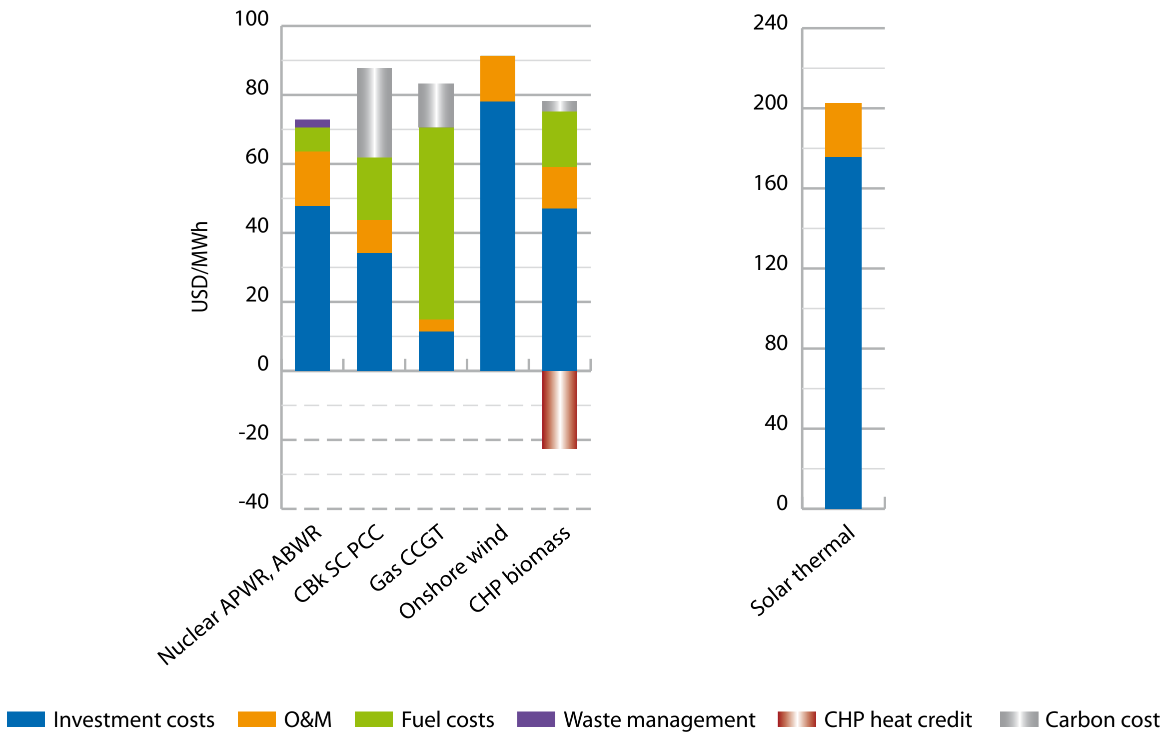


Figure 4.23b: US EPRI levelised costs of electricity
(at 10% discount rate)



4.2 Country-by-country data on electricity generating costs (numerical tables)

The following tables below contain the key information on electricity generating costs received for 190 plants from 23 different sources organised by country. For each plant type, the tables provide the specific cost break-down between investment costs,[3] operations and maintenance costs, as well as fuel and carbon costs. Fuel and carbon costs include waste management costs for nuclear fuels. The heat credit for CHP plants[4] is not indicated separately but included in the total levelised costs of electricity (LCOE).

The country-by-country cost summaries are provided separately for mainstream technologies (nuclear, coal with and without CC(S), gas, wind onshore plants) and for other technologies (renewables other than onshore wind, CHP, oil and fuel cells) at both 5% and 10% discount rates. This should allow readers to quickly proceed towards the information that is of greatest interest to them.

3. Investment costs correspond to the stacked bar graphs in Section 4.1 and are slightly different from Tables 3.7a to 3.7g in Section 3.2, where investment costs only include overnight costs and interest during construction. Here in the country-by-country tables, investment costs include also the relatively minor costs for refurbishment and decommissioning. For reasons of space, the latter could not be included as separate items. The interested reader is referred to Tables 3.7a to 3.7g.

4. Consistent with the LCOE methodology, total CO_2 emissions for CHP as well as their costs have been allocated to electricity output. While this raises carbon costs, it also raises the credit for heat output. The final impact on the LCOE for CHP is thus second-order.

Table 4.1a: Country-by-country data on electricity generating costs for mainstream technologies (at 5% discount rate)

Technology	Nuclear* Invest. costs	O&M	Fuel & carbon	LCOE	Coal Technology	Invest. costs	O&M	Fuel & carbon	LCOE
	USD/MWh					USD/MWh			
BELGIUM									
EPR-1600	44.53	7.20	9.33	**61.06**	Bk SC	21.20	8.73	52.39	**82.32**
					Bk SC	21.16	8.39	52.39	**81.94**
CANADA									
CZECH REPUBLIC									
PWR	45.67	14.74	9.33	**69.74**	Br PCC	32.51	8.53	43.50	**84.54**
					Br FBC	32.55	8.86	44.54	**85.94**
					Br IGCC	42.21	10.35	40.97	**93.53**
					Br FBC w/BioM	34.32	9.15	50.24	**93.71**
					Br PCC w/CC(S)	53.04	13.43	22.22	**88.69**
					Br FBC w/CC(S)	55.39	14.69	22.81	**92.89**
					Br IGCC w/CC(S)	56.34	12.26	19.69	**88.29**
					Br FBC w/BioM and CC(S)	55.39	14.98	32.22	**102.59**
FRANCE**									
EPR	31.10	16.00	9.33	**56.42**					
GERMANY									
PWR	31.84	8.80	9.33	**49.97**	Bk PCC	16.35	12.67	50.24	**79.26**
					Bk PCC w/CC(S)	27.36	20.11	37.81	**85.28**
					Br PCC	18.87	14.04	37.38	**70.29**
					Br PCC w/CC(S)	29.84	20.70	17.51	**68.06**
HUNGARY									
PWR	43.09	29.79	8.77	**81.65**					
ITALY									
JAPAN									
ABWR	23.88	16.50	9.33	**49.71**	Bk	22.53	10.06	55.49	**88.08**
KOREA									
OPR-1000	14.61	10.42	7.90	**32.93**	Bk PCC	8.59	4.25	55.57	**68.41**
APR-1400	12.20	8.95	7.90	**29.05**	Bk PCC	7.74	3.84	54.28	**65.86**
MEXICO									
					Bk PCC	17.77	6.51	50.11	**74.39**
NETHERLANDS									
PWR	39.72	13.71	9.33	**62.76**	Bk USC PCC	18.33	3.97	50.98	**82.04**
SLOVAK REPUBLIC									
VVER 440/ V213	33.91	19.35	9.33	**62.59**	Br SC FBC	23.73	8.86	87.43	**120.01**
SWITZERLAND									
PWR	49.07	19.84	9.33	**78.24**					
PWR	33.11	15.40	9.33	**57.83**					
UNITED STATES									
Adv Gen III+	26.53	12.87	9.33	**48.73**	Bk PCC	17.73	8.76	46.00	**72.49**
					Bk IGCC	20.46	8.37	46.03	**74.87**
					Bk IGCC w/CC(S)	29.96	11.31	26.76	**68.04**
NON-OECD MEMBERS									
BRAZIL									
"PWR Siemens/Areva"	38.11	15.54	11.64	**65.29**	Br SUBC PCC	10.69	37.89	15.39	**63.98**
CHINA									
CPR-1000	13.55	7.10	9.33	**29.99**	Bk USC PCC	5.29	1.64	23.06	**29.99**
CPR-1000	13.44	7.04	9.33	**29.82**	Bk SC	4.86	1.51	23.06	**29.42**
AP-1000	17.70	9.28	9.33	**36.31**	Bk SC	5.42	1.68	23.06	**30.16**
RUSSIA									
VVER-1150	22.76	16.73	4.00	**43.49**	Bk USC PCC	19.07	10.96	20.41	**50.44**
					Bk USC PCC w/CC(S)	39.13	21.58	26.10	**86.82**
					Bk SC PCC	17.74	10.20	22.83	**50.77**
SOUTH AFRICA									
					Bk SC PCC	19.73	4.87	7.59	**32.19**
INDUSTRY CONTRIBUTION									
EPRI									
APWR. ABWR	23.10	15.80	9.33	**48.23**	Bk SC PCC	17.89	9.70	43.93	**71.52**
ESAA									
					Bk SC AC	16.49	4.78	34.93	**56.20**
					Bk SC WC	16.10	4.74	33.13	**53.97**
					Bk USC AC	17.87	5.69	33.13	**56.69**
					Bk USC WC	17.38	5.64	31.51	**54.53**
					Bk USC AC w/CC(S)	32.21	11.10	15.57	**58.87**
					Bk USC WC w/CC(S)	31.02	10.98	14.61	**56.62**
					Bk IGCC w/CC(S)	34.51	11.94	14.31	**60.76**
					Br SC AC	18.15	5.36	40.65	**64.15**
					Br SC WC	17.71	5.31	38.79	**61.81**
					Br USC AC	19.53	6.41	38.21	**64.15**
					Br USC WC	19.47	6.35	35.94	**61.76**
					Br USC AC w/CC(S)	33.60	13.93	14.66	**62.19**
					Br USC WC w/CC(S)	32.07	13.79	13.52	**59.39**
EURELECTRIC/VGB									
EPR-1600	38.80	11.80	9.33	**59.93**	Bk	16.93	5.11	52.39	**74.43**
					Br	18.23	5.51	38.99	**62.73**
					Bk USC w/CC(S)	29.90	8.66	35.95	**74.51**

*Fuel and carbon costs for nuclear technology include waste management costs.
**The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

(cont.)

Table 4.1a: Country-by-country data on electricity generating costs for mainstream technologies
(at 5% discount rate)

Gas					Onshore wind			
Technology	Invest. costs	O&M	Fuel & carbon	LCOE	Technology	Invest. costs	O&M	LCOE
	USD/MWh					USD/MWh		
BELGIUM								
Single Shaft CCGT	11.73	6.33	71.65	**89.71**	3x2MWe	75.12	20.54	**95.65**
CCGT	10.39	6.56	74.91	**91.86**	1x2MWe	78.40	26.03	**104.43**
CCGT	9.71	4.06	72.28	**86.05**				
CCGT	11.32	5.71	72.28	**89.31**				
CANADA								
					33x3MWe	74.89	24.53	**99.42**
CZECH REPUBLIC								
CCGT	16.31	3.73	71.88	**91.92**	5x3MWe	123.94	21.92	**145.85**
CCGT w/CC(S)	26.37	6.22	65.62	**98.21**				
FRANCE**								
					15x3MWe	56.87	20.59	**90.20**
GERMANY								
CCGT	9.86	6.73	68.65	**85.23**	1x3MWe	69.19	36.62	**105.81**
Gas Turbine	5.00	5.38	108.39	**118.77**				
HUNGARY								
PWR	43.09	29.79	8.77	**81.65**				
ITALY								
CCGT	7.03	4.67	75.14	**86.85**	25x2MWe	102.72	42.78	**145.50**
JAPAN								
CCGT	16.00	5.55	83.59	**105.14**				
KOREA								
LNG CCGT	5.83	4.79	80.20	**90.82**				
LNG CCGT	5.75	4.12	79.93	**89.80**				
MEXICO								
CCGT	9.49	4.53	70.24	**84.26**				
NETHERLANDS								
CCGT	9.25	1.32	69.83	**77.94**	3MWe	67.69	17.83	**85.52**
SLOVAK REPUBLIC								
SWITZERLAND								
CCGT	15.27	7.83	70.94	**94.04**	3x2MWe	132.35	30.55	**162.90**
UNITED STATES								
CCGT	8.93	3.61	64.01	**76.56**	100x1.5MWe	39.76	8.63	**48.39**
AGT	5.75	4.48	81.25	**91.48**				
CCGT w/CC(S)	17.74	5.69	68.48	**91.90**				
NON-OECD MEMBERS								
BRAZIL								
CCGT	20.66	5.40	57.79	**83.85**				
CHINA								
CCGT	4.86	2.81	28.14	**35.81**	200MWe (Park)	35.44	15.51	**50.95**
CCGT	5.26	3.04	28.14	**36.44**	33x1.5MWe	44.64	19.54	**64.18**
					41x0.85MWe	57.86	25.33	**83.19**
					30MWe (Park)	61.91	27.11	**89.02**
RUSSIA								
CCGT	11.05	7.55	39.14	**57.75**	100x1MWe	47.96	15.43	**63.39**
SOUTH AFRICA								
					Bk SC PCC	19.73	4.87	**32.19**
INDUSTRY CONTRIBUTION								
EPRI								
CCGT	6.82	3.39	68.51	**78.72**	50x2MWe	48.53	13.35	**61.87**
ESAA								
CCGT AC	15.02	3.64	51.23	**69.89**	50x3MWe	65.48	11.41	**76.89**
CCGT WC	14.17	3.58	49.28	**67.03**				
OCGT AC	6.49	7.67	65.67	**79.82**				
EURELECTRIC/VGB								
CCGT	11.11	3.93	71.04	**86.08**	100MWe (Park)	77.80	34.91	**112.71**

*Fuel and carbon costs for nuclear technology include waste management costs.
**The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

Table 4.1b: Country-by-country data on electricity generating costs for mainstream technologies
(at 10% discount rate)

Nuclear*					Coal				
Technology	Invest. costs	O&M	Fuel & carbon	LCOE	Technology	Invest. costs	O&M	Fuel & carbon	LCOE
	USD/MWh					USD/MWh			
BELGIUM									
EPR-1600	92.61	7.20	9.33	**109.14**	Bk SC	39.30	8.73	52.39	**100.43**
					Bk SC	39.23	8.39	52.39	**100.01**
CANADA									
CZECH REPUBLIC									
PWR	90.99	14.74	9.33	**115.06**	Br PCC	62.10	8.53	43.50	**114.12**
					Br FBC	62.24	8.86	44.54	**115.64**
					Br IGCC	81.92	10.35	40.97	**133.24**
					Br FBC w/BioM	65.62	9.15	50.24	**125.01**
					Br PCC w/CC(S)	100.47	13.43	22.22	**136.12**
					Br FBC w/CC(S)	105.07	14.69	22.81	**142.57**
					Br IGCC w/CC(S)	108.69	12.26	19.69	**140.64**
					Br FBC w/BioM and CC(S)	105.07	14.98	32.22	**152.27**
FRANCE**									
EPR	67.06	16.00	9.33	**92.38**					
GERMANY									
PWR	64.51	8.80	9.33	**82.64**	Bk PCC	31.19	12.67	50.24	**94.10**
					Bk PCC w/CC(S)	51.69	20.11	37.81	**109.61**
					Br PCC	35.99	14.04	37.38	**87.41**
					Br PCC w/CC(S)	56.39	20.70	17.51	**94.60**
HUNGARY									
PWR	82.61	29.84	9.18	**121.62**					
ITALY									
JAPAN									
ABWR	50.63	16.50	9.33	**76.46**	Bk	41.49	10.06	55.49	**107.03**
KOREA									
OPR-1000	30.07	10.42	7.90	**48.38**	Bk PCC	14.42	4.25	55.57	**74.25**
APR-1400	25.24	8.95	7.90	**42.09**	Bk PCC	13.00	3.84	54.28	**71.12**
MEXICO									
					Bk PCC	35.66	6.51	50.11	**92.27**
NETHERLANDS									
PWR	82.02	13.71	9.33	**105.06**	Bk USC PCC and BioM	36.11	3.97	50.98	**99.82**
SLOVAK REPUBLIC									
VVER 440/ V213	71.70	16.89	9.33	**97.92**	Br SC FBC	45.35	8.86	87.43	**141.64**
SWITZERLAND									
PWR	107.33	19.84	9.33	**136.50**					
PWR	72.12	15.40	9.33	**96.84**					
UNITED STATES									
Adv Gen III+	55.20	12.87	9.33	**77.39**	Bk PCC	33.09	8.76	46.00	**87.85**
					Bk IGCC	38.20	8.37	46.03	**92.61**
					Bk IGCC w/CC(S)	55.85	11.31	26.76	**93.92**
NON-OECD MEMBERS									
BRAZIL									
"PWR Siemens/Areva"	78.11	15.54	11.64	**105.29**	Br SUBC PCC	19.70	43.93	15.39	**79.02**
CHINA									
CPR-1000	27.57	7.10	9.33	**44.00**	Bk USC PCC	9.47	1.64	23.06	**34.17**
CPR-1000	27.34	7.04	9.33	**43.72**	Bk SC	8.69	1.51	23.06	**33.26**
AP-1000	36.01	9.28	9.33	**54.61**	Bk SC	9.69	1.68	23.06	**34.43**
RUSSIA									
VVER-1150	47.21	16.94	4.00	**68.15**	Bk USC PCC	34.53	10.96	20.41	**65.91**
					Bk USC PCC w/CC(S)	70.65	21.58	26.10	**118.34**
					Bk SC PCC	32.13	10.20	22.83	**65.15**
SOUTH AFRICA									
					Bk SC PCC	41.53	4.87	7.59	**53.99**
INDUSTRY CONTRIBUTION									
EPRI									
APWR.ABWR	47.73	15.80	9.33	**72.87**	Bk SC PCC	34.05	9.70	43.93	**87.68**
ESAA									
					Bk SC AC	30.19	4.78	34.93	**69.90**
					Bk SC WC	29.47	4.74	33.13	**67.34**
					Bk USC AC	32.72	5.69	33.13	**71.54**
					Bk USC WC	31.82	5.64	31.51	**68.97**
					Bk USC AC w/CC(S)	58.99	11.09	15.57	**85.66**
					Bk USC WC w/CC(S)	56.82	10.98	14.61	**82.42**
					Bk IGCC w/CC(S)	63.38	11.94	14.31	**89.62**
					Br SC AC	33.21	5.36	40.65	**79.22**
					Br SC WC	32.42	5.31	38.79	**76.52**
					Br USC AC	35.74	6.41	38.21	**80.36**
					Br USC WC	36.33	6.35	35.94	**78.63**
					Br USC AC w/CC(S)	61.52	13.93	14.66	**90.11**
					Br USC WC w/CC(S)	58.72	13.79	13.52	**86.03**
EURELECTRIC/VGB									
EPR-1600	84.71	11.80	9.33	**105.84**	Bk	32.60	5.11	52.39	**90.11**
					Br	35.11	5.51	38.99	**79.61**
					Bk USC w/CC(S)	57.39	8.66	35.95	**102.00**

*Fuel and carbon costs for nuclear technology include waste management costs.
**The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

(cont.)

Table 4.1b: Country-by-country data on electricity generating costs for mainstream technologies
(at 10% discount rate)

Gas					Onshore wind			
Technology	Invest. costs	O&M	Fuel & carbon	LCOE	Technology	Invest. costs	O&M	LCOE
	USD/MWh					USD/MWh		
BELGIUM								
Single Shaft CCGT	20.31	6.33	71.65	**98.29**	3x2MWe	115.69	20.54	**136.23**
CCGT	18.07	6.56	74.91	**99.54**	1x2MWe	120.75	26.03	**146.78**
CCGT	16.23	4.06	72.28	**92.57**				
CCGT	18.91	5.71	72.28	**96.90**				
CANADA								
					33x3MWe	115.38	23.85	**139.23**
CZECH REPUBLIC								
CCGT	28.87	3.73	71.88	**104.48**	5x3MWe	197.27	21.92	**219.18**
CCGT w/CC(S)	46.06	6.22	65.62	**117.90**				
FRANCE**								
					15x3MWe	88.84	20.59	**121.57**
GERMANY								
CCGT	17.44	6.73	68.65	**92.81**	1x3MWe	106.34	36.62	**142.96**
Gas Turbine	8.84	5.38	108.39	**122.61**				
HUNGARY								
ITALY								
CCGT	11.86	4.67	74.91	**91.44**	25x2MWe	187.20	42.78	**229.97**
JAPAN								
CCGT	30.39	5.55	83.59	**119.53**				
KOREA								
LNG CCGT	9.70	4.79	80.20	**94.70**				
LNG CCGT	9.57	4.12	79.93	**93.63**				
MEXICO								
CCGT	16.87	4.74	70.24	**91.85**				
NETHERLANDS								
CCGT	15.33	1.32	69.83	**82.40**	3MWe	104.26	17.78	**122.04**
SLOVAK REPUBLIC								
SWITZERLAND								
CCGT	26.42	7.83	70.94	**105.19**	3x2MWe	203.77	30.55	**234.32**
UNITED STATES								
CCGT	15.14	3.61	64.01	**82.76**	100x1.5MWe	61.84	8.63	**70.47**
AGT	9.35	4.48	81.25	**95.08**				
CCGT w/CC(S)	30.02	5.69	68.48	**104.19**				
NON-OECD MEMBERS								
BRAZIL								
CCGT	31.66	5.40	57.79	**94.84**				
CHINA								
CCGT	8.07	2.81	28.14	**39.01**	200MWe (Park)	56.49	15.51	**72.01**
CCGT	8.73	3.04	28.14	**39.91**	33x1.5MWe	71.16	19.54	**90.70**
					41x0.85MWe	92.22	25.33	**117.55**
					30MWe (Park)	98.69	27.11	**125.80**
RUSSIA								
CCGT	18.44	7.55	39.14	**65.13**	100x1MWe	74.17	15.43	**89.60**
SOUTH AFRICA								
					Bk SC PCC	19.73	4.87	**32.19**
INDUSTRY CONTRIBUTION								
EPRI								
CCGT	11.35	3.39	68.51	**83.25**	50x2MWe	77.96	13.35	**91.31**
ESAA								
CCGT AC	24.77	3.64	51.23	**79.64**	50x3MWe	102.54	11.41	**113.95**
CCGT WC	23.49	3.58	49.28	**76.36**				
OCGT AC	10.58	7.67	65.67	**83.91**				
EURELECTRIC/VGB								
CCGT	18.87	3.93	71.04	**93.84**	100MWe (Park)	119.79	34.91	**154.71**

*Fuel and carbon costs for nuclear technology include waste management costs.
**The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

Table 4.2a: Country-by-country data on electricity generating costs for other technologies (at 5% discount rate)							
Hydro				Solar			
Technology	Invest. costs	O&M	LCOE	Technology	Invest. costs	O&M	LCOE
	USD/MWh				USD/MWh		
AUSTRIA							
Small-2MWe	44.37	4.25	**48.62**				
BELGIUM							
CANADA							
				PV Park-10MWe	212.38	14.98	**227.37**
				PV Indus-1MWe	274.33	13.69	**288.02**
				PV Com-0.1MWe	398.81	11.16	**409.96**
				PV Res-0.005MWe	460.16	10.14	**470.30**
CZECH REPUBLIC							
Large-10MWe	225.24	6.39	**231.63**	PV-1MWe	362.93	29.95	**392.88**
Small-5MWe	149.08	6.97	**156.05**				
FRANCE							
				PV-10MWe	184.36	80.97	**286.62**
GERMANY							
				PV (Open Space)-0.5MWe	251.75	52.85	**304.59**
				PV (Roof)-0.002MWe	291.26	61.05	**352.31**
ITALY							
				PV-6MWe	356.42	53.94	**410.36**
JAPAN							
Large-19MWe	116.77	36.11	**152.88**				
MEXICO							
NETHERLANDS							
				PV-0.03MWe (Indus)	434.77	35.16	**469.93**
				PV-0.0035MWe (Res)	569.74	57.13	**626.87**
SLOVAK REPUBLIC							
SWEDEN							
Large-70MWe	54.73	15.17	**74.09**				
SWITZERLAND							
Small-0.3MWe	51.81	59.73	**111.53**				
UNITED STATES							
				PV-5MWe	209.74	5.71	**215.45**
				Thermal-100MWe	183.59	27.59	**211.18**
NON-OECD MEMBERS							
BRAZIL							
Large-800MWe	16.39	2.31	**18.70**				
Large-300MWe	15.10	2.31	**17.41**				
Large-15MWe	33.32	5.20	**38.53**				
CHINA							
Large-18134MWe	19.24	9.85	**29.09**	PV-20MWe	107.21	15.65	**122.86**
Large-6277MWe	14.33	2.54	**16.87**	PV-10MWe	162.60	23.73	**186.33**
Large-4783MWe	10.12	1.37	**11.49**	PV-10MWe	108.82	15.88	**124.70**
				PV-10MWe	156.35	22.82	**179.16**
RUSSIA							
SOUTH AFRICA							
INDUSTRY CONTRIBUTION							
EPRI							
				Thermal-80MWe	109.30	26.86	**136.16**
ESAA							
EURELECTRIC/VGB							
River-1000MWe	29.71	5.02	**34.74**	PV-1MWe	215.43	29.30	**244.73**
Pump-1000MWe	62.40	10.55	**72.95**	Thermal-1MWe	134.65	36.62	**171.27**

(cont.)

Table 4.2a: Country-by-country data on electricity generating costs for other technologies
(at 5% discount rate)

CHP					Other technologies				
Technology	Invest. costs	O&M	"Fuel & carbon"	LCOE	Technology	Invest. costs	O&M	"Fuel & carbon"	LCOE
	USD/MWh					USD/MWh			
AUSTRIA									
CHP Gas CCGT	7.44	3.91	76.49	**50.79**					
BELGIUM									
					Offshore wind	134.12	54.09	0.00	**188.21**
CANADA									
					Offshore wind	101.76	35.50	0.00	**137.26**
CZECH REPUBLIC									
CHP Br Coal Turbine	38.03	9.60	26.72	**42.12**	Geothermal	145.77	19.02	0.00	**164.78**
CHP Gas CCGT	19.11	4.53	63.06	**74.62**					
CHP Municipal Waste Incin.	213.42	49.36	28.80	**247.27**					
FRANCE									
					Offshore wind	90.94	32.35	0.00	**143.69**
					Biogas	30.41	41.18	2.65	**79.67**
GERMANY									
CHP Black Coal	25.47	16.19	64.20	**38.37**	Offshore wind	91.69	46.26	0.00	**137.94**
CHP Gas	12.67	8.73	89.53	**67.97**					
ITALY									
CHP Gas	13.34	15.50	74.91	**75.59**					
JAPAN									
MEXICO									
					Oil Engine	17.57	19.91	67.16	**104.63**
NETHERLANDS									
CHP Gas CCGT	12.06	8.79	95.99	**94.45**	Offshore wind	118.10	10.63	0.00	**128.72**
CHP Gas CCGT	16.60	15.38	100.67	**103.34**	BioM and BioG	81.19	4.49	74.82	**160.50**
					Biomass	56.30	4.52	69.06	**129.88**
SLOVAK REPUBLIC									
CHP Gas and BioM CCGT	10.42	6.25	73.77	**65.06**					
SWEDEN									
					Wave	92.89	75.86	0.00	**168.75**
SWITZERLAND									
CHP Gas CCGT	9.60	6.96	68.56	**82.85**					
CHP Biogas	102.50	167.19	0.00	**251.56**					
UNITED STATES									
CHP Simple Gas Turbine	7.18	1.07	82.95	**40.58**	Offshore wind	77.39	23.63	0.00	**101.02**
					Biomass	31.38	15.66	6.73	**53.77**
					Biogas	22.69	24.84	0.00	**47.53**
					Geothermal	14.26	18.21	0.00	**32.48**
					Fuel Cell	62.16	49.81	69.20	**181.17**
NON-OECD MEMBERS									
BRAZIL									
					Biomass	32.36	26.25	19.13	**77.73**
CHINA									
CHP Black Coal	6.44	0.92	49.22	**48.73**					
RUSSIA									
CHP Bk PCC	23.65	12.95	31.24	**24.12**					
CHP Gas CCGT Large	13.35	8.80	46.95	**47.28**					
CHP Gas CCGT Small	18.05	11.90	49.00	**59.58**					
CHP Gas Turbine Large	11.49	7.85	62.02	**43.49**					
CHP Gas Turbine Small	14.43	9.86	65.87	**53.64**					
SOUTH AFRICA									
					Diesel OCGT	4.38	24.26	364.59	**393.24**
INDUSTRY CONTRIBUTION									
EPRI									
CHP Biomass	27.90	12.09	19.09	**36.57**					
ESAA									
					Geothermal	34.02	5.47	0.00	**39.48**
					Wave	144.04	27.87	0.00	**171.91**
					Tidal	101.51	185.02	0.00	**286.53**
EURELECTRIC/VGB									
					Offshore wind (Close)	77.63	43.30	0.00	**120.93**
					Offshore wind (Far)	83.20	53.97	0.00	**137.17**

Table 4.2b: Country-by-country data on electricity generating costs for other technologies
(at 10% discount rate)

Hydro				Solar			
Technology	Invest. costs	O&M	LCOE	Technology	Invest. costs	O&M	LCOE
	USD/MWh				USD/MWh		
AUSTRIA							
Small-2MWe	88.33	4.25	**92.58**				
BELGIUM							
CANADA							
				PV Park-10MWe	327.23	14.49	**341.72**
				PV Indus-1MWe	422.67	13.29	**435.96**
				PV Com-0.1MWe	614.46	10.83	**625.29**
				PV Res-0.005MWe	708.99	9.84	**718.83**
CZECH REPUBLIC							
Large-10MWe	452.94	6.39	**459.32**	PV-1MWe	581.32	29.95	**611.26**
Small-5MWe	292.14	6.97	**299.11**				
FRANCE							
				PV-10MWe	285.89	80.97	**388.14**
GERMANY							
				PV (Open Space)-0.5MWe	386.93	52.85	**439.77**
				PV (Roof)-0.002MWe	447.66	61.05	**508.71**
ITALY							
				PV-6MWe	562.04	53.94	**615.98**
JAPAN							
Large-19	245.41	36.11	**281.51**				
MEXICO							
NETHERLANDS							
				PV-0.03MWe (Indus)	669.62	35.16	**704.78**
				PV-0.0035MWe (Res)	877.50	57.13	**934.63**
SLOVAK REPUBLIC							
SWEDEN							
Large-70MWe	117.99	15.17	**139.69**				
SWITZERLAND							
Small-0.3MWe	110.06	59.73	**169.79**				
UNITED STATES							
				PV-5MWe	327.07	5.71	**332.78**
				Thermal-100MWe	296.13	27.59	**323.71**
NON-OECD MEMBERS							
BRAZIL							
Large-800MWe	31.88	2.42	**34.30**				
Large-300MWe	30.71	2.42	**33.13**				
Large-15MWe	55.66	5.80	**61.46**				
CHINA							
Large-18134MWe	41.65	9.85	**51.50**	PV-20MWe	170.90	15.65	**186.54**
Large-6277MWe	31.03	2.54	**33.57**	PV-10MWe	259.19	23.73	**282.92**
Large-4783MWe	21.92	1.37	**23.28**	PV-10MWe	173.46	15.88	**189.34**
				PV-10MWe	249.22	22.82	**272.04**
RUSSIA							
SOUTH AFRICA							
INDUSTRY CONTRIBUTION							
EPRI							
				Thermal-80MWe	175.59	26.86	**202.45**
ESAA							
EURELECTRIC/VGB							
River-1000MWe	65.87	5.02	**70.89**	PV-1MWe	331.74	29.30	**361.03**
Pump-1000MWe	138.33	10.55	**148.88**	Thermal-1MWe	207.34	36.62	**243.96**

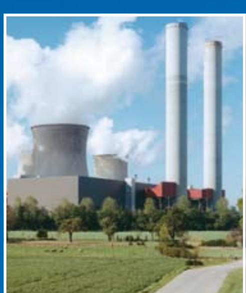
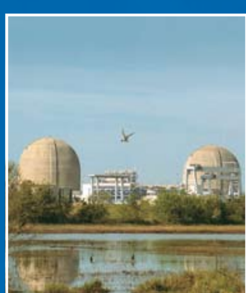
(cont.)

Table 4.2b: Country-by-country data on electricity generating costs for other technologies
(at 10% discount rate)

CHP					Other technologies				
Technology	Invest. costs	O&M	"Fuel & carbon"	LCOE	Technology	Invest. costs	O&M	"Fuel & carbon"	LCOE
	USD/MWh					USD/MWh			
AUSTRIA									
CHP CCGT	12.72	3.91	76.49	**56.07**					
BELGIUM									
					Offshore wind	206.71	54.09	0.00	**260.80**
CANADA									
					Offshore wind	160.38	34.55	0.00	**194.93**
CZECH REPUBLIC									
CHP Br Coal Turbine	65.76	9.60	65.62	**108.75**	Geothermal	248.44	21.49	0.00	**269.93**
CHP Gas CCGT	33.44	4.53	63.06	**88.95**					
CHP Municipal Waste Incin.	366.09	49.36	28.80	**399.94**					
FRANCE									
					Offshore wind	142.00	32.35	0.00	**194.74**
					Biogas	46.21	41.18	2.65	**95.47**
GERMANY									
CHP Black Coal	48.59	16.19	64.20	**61.48**	Offshore wind	140.51	46.26	0.00	**186.76**
CHP Gas	22.42	8.73	89.53	**77.81**					
ITALY									
CHP Gas	23.27	15.08	74.91	**85.11**					
JAPAN									
MEXICO									
					Oil Engine	31.22	20.66	67.16	**119.03**
NETHERLANDS									
CHP Gas CCGT	23.54	8.79	95.99	**105.94**	Offshore wind	185.91	10.63	0.00	**196.53**
CHP Gas CCGT	32.42	15.38	100.67	**119.16**	BioM and BioG	117.73	4.49	74.82	**197.04**
					Biomass	81.63	4.52	69.06	**155.21**
SLOVAK REPUBLIC									
CHP Gas and BioM CCGT	17.95	6.25	73.77	**72.26**					
SWEDEN									
					Wave	148.29	75.86	0.00	**224.15**
SWITZERLAND									
CHP Gas CCGT	16.87	6.96	68.56	**90.12**					
CHP Biogas	177.62	167.19	0.00	**326.68**					
UNITED STATES									
CHP Simple Gas Turbine	11.66	1.07	82.95	**45.07**	Offshore wind	122.81	23.63	0.00	**146.44**
					Biomass	58.43	15.66	6.73	**80.82**
					Biogas	38.48	24.84	0.00	**63.32**
					Geothermal	26.17	20.58	0.00	**46.76**
					Fuel Cell	94.13	49.81	69.20	**213.14**
NON-OECD MEMBERS									
BRAZIL									
					Biomass	51.98	31.49	19.13	**102.60**
CHINA									
CHP Black Coal	10.41	0.92	49.22	**52.70**					
RUSSIA									
CHP Bk PCC	44.94	12.95	31.24	**45.40**					
CHP Gas CCGT Large	23.08	8.80	46.95	**57.00**					
CHP Gas CCGT Small	31.20	11.90	49.00	**72.73**					
CHP Gas Turbine Large	19.16	7.85	62.02	**51.16**					
CHP Gas Turbine Small	24.07	9.86	65.87	**63.28**					
SOUTH AFRICA									
					Diesel OCGT	7.76	24.26	364.59	**396.62**
INDUSTRY CONTRIBUTION									
EPRI									
CHP Biomass	46.96	12.09	19.09	**55.64**					
ESAA									
					Geothermal	63.13	5.47	0.00	**68.60**
					Wave	214.00	27.87	0.00	**241.87**
					Tidal	160.40	187.50	0.00	**347.90**
EURELECTRIC/VGB									
					Offshore wind (Close)	119.58	43.30	0.00	**162.89**
					Offshore wind (Far)	128.16	53.97	0.00	**182.13**

Part 2

Sensitivity analyses and boundary issues


Median case

In order to perform a series of sensitivity analyses, the EGC Expert Group chose to test the impact of changes in underlying parameters on a LCOE calculated using median values from the sample of OECD countries' reported data, for the main cost categories (capital, O&M, fuel and CO_2 costs) as well for other specifications (capacity, thermal efficiencies and load factors for each of the main types of power plants. Median values were preferable to the mean given the wide dispersion of data among countries observed for all technologies.

It should be noted however that the EGC database is not a statistical sample; for example, there is a large amount of data from certain countries, such as Australia or the Czech Republic.[1] On the other hand, current cost conditions in key markets, namely for renewable technologies, are not included in the EGC database as the respective countries did not report any data to the study, this way over-representing smaller markets.[2]

Table 5.1 provides an overview of the characteristics of the data points for each main generation technology.

1. Of the 22 plants used for calculating the median case for supercritical and ultra-supercritical coal-fired power plants (both black and brown), 8 are thus from Australia. Of the 8 plants used to calculate the median value for coal-fired power plants with carbon capture equipment, 4 are from Australia. This over-representation of Australia, which has the lowest reported coal prices of all OECD countries, also explains the otherwise counterintuitive result that the median fuel cost for coal-fired power generation with CC(S) is lower than for coal-fired power generation without CC(S) despite sensibly lower conversion efficiency. In general, data for the costs of coal generation with carbon capture is more uncertain (with both upside and downside risks) than that for other technologies due to the fact that this new technology has not yet been deployed on an industrial scale.

2. In particular, the sample of data for renewables was small and limited to a restricted set of responding countries. As a consequence of this "self-selection" problem, the results for renewables are not representative of the current average situation in OECD renewables markets. Internal IEA analysis on renewables and forthcoming numbers on renewables in key IEA publications (among which WEO 2009, ETP 2010 and other) may substantially differ from the EGC sample as a result of including a larger sample of countries.

Table 5.1: Overview of the data points for each main generation technology

OECD MEDIAN CASE NUCLEAR	Net Capacity	Owner's and Construction	Overnight cost	Fuel cost	CO_2 cost	O&M cost
number of countries	13	13	13	13	13	13
count	15	15	15	15	15	15
max	1 650	5 862.86	5 862.86	9.33	0.00	29.81
min	954	1 505.92	1 556.40	7.90	0.00	7.20
mean	1 387	3 723.63	4 079.33	9.10	0.00	14.66
median	**1 400**	**3 681.07**	**4 101.51**	**9.33**	**0.00**	**14.74**
delta	696	4 356.94	4 306.46	1.43	0.00	22.61
std.dev	245	1 226.70	1 334.33	0.51	0.00	5.53

OECD MEDIAN CASE SC/ USC COAL	Net Capacity	Thermal Efficiency	Owner's and Construction	Overnight cost	Fuel cost	CO_2 cost	O&M cost
number of countries	11	11	11	11	11	11	11
count	22	22	22	22	22	22	22
max	1 560	46.0%	3 319.33	3 485.30	31.61	32.16	14.04
min	552	31.3%	787.15	806.68	7.51	22.07	3.84
mean	798	40.8%	1 960.21	2 125.67	18.82	25.27	7.02
median	**750**	**41.1%**	**1 915.65**	**2 133.49**	**18.21**	**23.96**	**6.02**
delta	1 007.82	14.7%	2 532.19	2 678.62	24.10	10.09	10.20
std.dev	257	4.3%	509.21	537.21	9.60	2.78	2.77

OECD MEDIAN CASE SC/ USC COAL w/CC(S)	Net Capacity	Thermal Efficiency	Owner's and Construction	Overnight cost	Fuel cost	CO_2 cost	O&M cost
number of countries	5	5	5	5	5	5	5
count	8	8	8	8	8	8	8
max	970	39.00%	5 053.66	5 811.71	34.56	4.03	20.70
min	416	25.00%	2 802.28	3 222.62	9.81	1.41	8.66
mean	586	33.33%	3 471.35	3 961.84	18.34	3.14	14.09
median	**474**	**34.75%**	**3 336.96**	**3 837.51**	**13.04**	**3.22**	**13.61**
delta	554	14.00%	2 251.38	2 589.09	24.75	2.62	12.04
std.dev	210	5.37%	680.11	799.23	10.18	0.83	4.29

OECD MEDIAN CASE GAS-CCGT	Net Capacity	Thermal Efficiency	Owner's and Construction	Overnight cost	Fuel cost	CO_2 cost	O&M cost
number of countries	13	13	13	13	13	13	13
count	19	19	19	19	19	19	19
max	1 600	60.0%	1 605.81	1 677.60	72.58	14.74	7.83
min	230	39.9%	618.00	634.50	39.68	9.60	1.32
mean	600	55.1%	1 053.07	1 121.20	59.77	11.12	4.66
median	**480**	**57.0%**	**1 018.07**	**1 068.97**	**61.12**	**10.54**	**4.48**
delta	1 370	20.1%	987.81	1 043.10	32.90	5.14	6.51
std.dev	309	4.8%	319.16	352.91	8.60	1.47	1.50

OECD MEDIAN CASE WIND ONSHORE	Net Capacity	Load Factor	Owner's and Construction	Overnight cost	Fuel cost	CO_2 cost	O&M cost
number of countries	12	12	12	12	12	12	12
count	13	13	13	13	13	13	13
max	150	41.0%	3 539.26	3 716.22	0.00	0.00	42.78
min	2	20.5%	1 735.00	1 845.00	0.00	0.00	8.63
mean	56	27.2%	2 297.79	2 422.64	0.00	0.00	23.79
median	**45**	**25.7%**	**2 236.80**	**2 348.64**	**0.00**	**0.00**	**21.92**
delta	148	20.5%	1 804.26	1 871.22	0.00	0.00	34.15
std.dev	57	5.5%	545.58	575.92	0.00	0.00	10.21

OECD MEDIAN CASE SOLAR PV	Net Capacity	Load Factor	Owner's and Construction	Overnight cost	Fuel cost	CO_2 cost	O&M cost
number of countries	8	8	8	8	8	8	8
count	13	13	13	13	13	13	13
max	10	24.9%	7 029.18	7 380.64	0.00	0.00	80.97
min	0	9.7%	3 067.11	3 266.56	0.00	0.00	5.71
mean	3	15.4%	5 225.96	5 544.29	0.00	0.00	35.02
median	**1**	**13.0%**	**5 759.35**	**6 005.79**	**0.00**	**0.00**	**29.95**
delta	10	15.2%	3 962.07	4 114.07	0.00	0.00	75.26
std.dev	4	5.6%	1 372.66	1 439.57	0.00	0.00	24.07

Notes:
- Count refer to the number of data points or plants taken into account for each technology.
- All costs are expressed in USD (2008 average values). Capital costs (owner's and construction cost) are expressed in USD/kW; fuel, CO_2 and O&M costs are expressed in USD/MWh.
- Owner's and construction cost include pre-construction and EPC costs but exclude contingency and IDC.
- Overnight costs include owner's, construction and contingency costs but exclude IDC.

The LCOE resulting from using median vales cannot be associated with any particular plant in the sample, nor are the "median plants" internally consistent. They are a working tool necessary for the sensitivity analyses, constructed partly on the basis of incomplete data and sometimes from a reduced sample, in particular for certain technologies. They should not be interpreted as the Secretariat's view on the future costs of generating electricity in any particular location, from any fuel source or technology.

Table 5.2 summarises the median cost values and specifications used in this chapter for nuclear, gas-fired, coal-fired plants with and without carbon capture equipment, onshore wind and solar PV plants based on the EGC sample of plants for OECD countries. Keeping with the tradition of the EGC series, the median case value of the LCOE necessary for the sensitivity analyses was calculated for all technologies for both 5% and 10% discount rates.

Table 5.2: Median case specifications summary

Median case specifications		Nuclear	CCGT	SC/USC coal	Coal w/90%CC(S)	Onshore wind	Solar PV
Capacity (MW)		1 400.00	480.00	750.00	474.40	45.00	1.00
Owner's and construction		3 681.07	1 018.07	1 915.65	3 336.96	2 236.80	5 759.35
Overnight cost ($/kW)*		4 101.51	1 068.97	2 133.49	3 837.51	2 348.64	6 005.79
O&M ($/MWh)		14.74	4.48	6.02	13.61	21.92	29.95
Fuel cost ($/MWh)		9.33	61.12	18.21	13.04	0.00	0.00
CO_2 cost ($/MWh)		0.00	10.54	23.96	3.22	0.00	0.00
Efficiency (net, LHV)		33%	57%	41.1%	34.8%	-	-
Load factor (%)		85%	85%	85%	85%	26%	13%
Lead time (years)		7	2	4	4	1	1
Expected lifetime (years)		60	30	40	40	25	25
LCOE ($/MWh)	5%	58.53	85.77	65.18	62.07	96.74	410.81
	10%	98.75	92.11	80.05	89.95	137.16	616.55

*Overnight costs include owner's, construction and contingency costs but exclude IDC.

Notes:
- Years refer to time of plant coming on line i.e. duration of plant construction.
- All costs are expressed in USD (2008 average values 1 USD=0.684 EUR).
- Construction costs include owner's and EPC costs but exclude contingency and IDC. The LCOE includes total investment costs, i.e. construction costs plus contingency for unforeseen technical and regulatory difficulties and IDC. Overnight costs were calculated applying the study generic assumptions (15% contingency for nuclear and coal with CC(S) and 5% for coal without CC(S), gas, wind and solar technologies).
- Thermal plant efficiencies are net (sent out basis), LHV (lower heating value). The difference between lower and higher heating value, based on IEA conventions, is 5% for coal and 10% for gas.

Variations in individual median cost values and assumptions were subsequently performed with the key results presented in Chapter 6.

Sensitivity analyses

The objective of this chapter is to test the sensitivity of the results of the cost calculations to variations in the underlying assumptions on key parameters such as discount rates, construction costs, lead times, fuel and CO_2 prices, lifetime of plants and load factors. Uncertainties regarding these variables, and their resulting risks, are a reality for energy markets. In addition, all these parameters vary widely across different countries, and even within countries.

Variations in individual median cost values and assumptions have been performed on the basis of the Median case defined in Chapter 5.

Table 6.1: Median case

Median case specifications		Nuclear	CCGT	US/USC coal	Coal w/90%CC(S)	Onshore wind	Solar PV
Capacity (MW)		1 400.0	480.0	750.0	474.4	45.0	1.0
Owner's and construction		3 681.07	1 018.07	1 915.65	3 336.96	2 236.80	5 759.35
Overnight cost ($/kW)*		4 101.51	1 068.97	2 133.49	3 837.51	2 348.64	6 005.79
O&M ($/MWh)		14.74	4.48	6.02	13.61	21.92	29.95
Fuel cost ($/MWh)		9.33	61.12	18.21	13.04	0.00	0.00
CO_2 cost ($/MWh)		0.00	10.54	23.96	3.22	0.00	0.00
Efficiency (net, LHV)		33%	57%	41.1%	34.8%	-	-
Load factor (%)		85%	85%	85%	85%	26%	13%
Lead time (years)		7	2	4	4	1	1
Expected lifetime (years)		60	30	40	40	25	25
LCOE ($/MWh)	5%	58.53	85.77	65.18	62.07	96.74	410.81
	10%	98.75	92.11	80.05	89.95	137.16	616.55
*Overnight costs include owner's, construction and contingency costs but exclude IDC.							

Notes:
- Years refer to the duration of plant construction.
- All costs are expressed in USD (2008 average values: 1 USD = 0.684 EUR).
- Construction costs include owner's and EPC costs but exclude contingency and IDC.
- Thermal plant efficiencies are net. Fuel price calculations are based on the lower heating value (LHV) of fossil fuels.

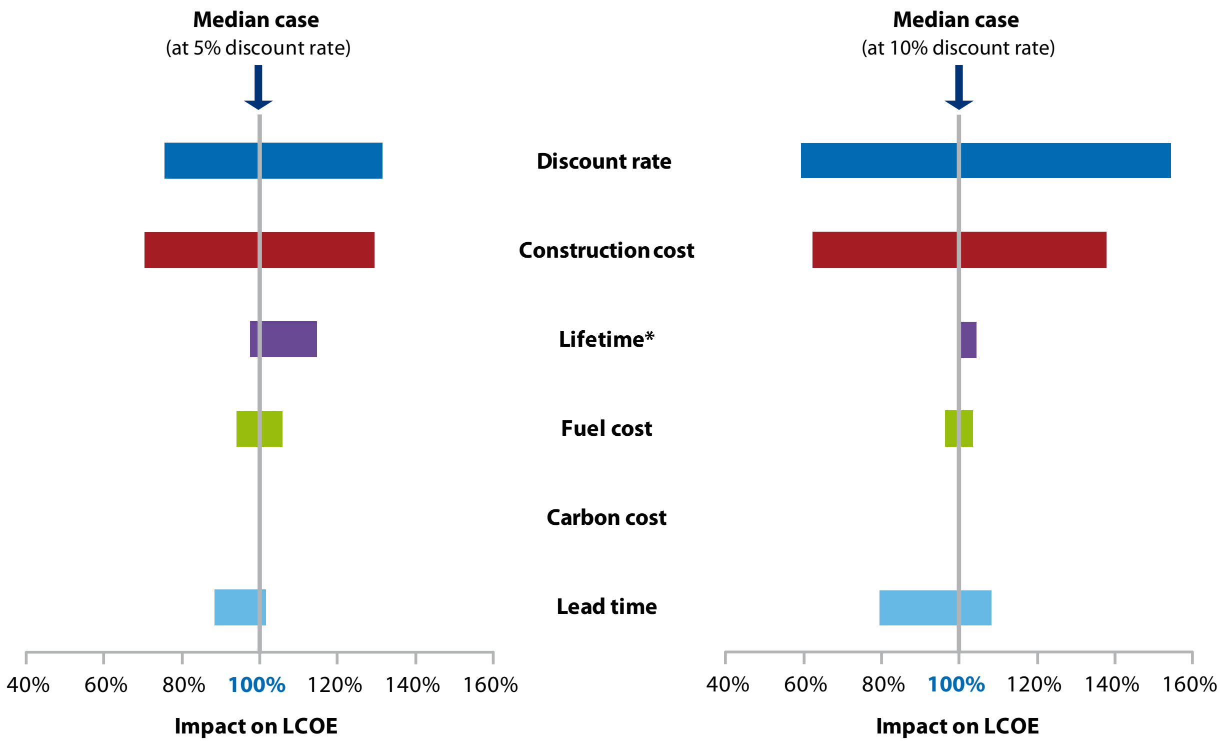
Section 6.1 presents the impact on the levelised cost of electricity (LCOE) of a uniform ± 50% change in all the key parameters mentioned above in order to compare their relative importance for the overall LCOE. Section 6.2 summarises the results of the sensitivity of the LCOE to variations in key parameters individually considered. Finally, section 6.3 includes a qualitative discussion of different variables affecting the LCOE.

6.1 Multi-dimensional sensitivity analysis

This section presents for each technology the results of a uniform ± 50% change in the values used in the Median case for each parameter individually considered (parameter by parameter) to allow a ranking of different parameters according to their relative importance in determining LCOE. The tornado graphs below illustrate the relative impact of the ±50% variation in the values of individual parameters on the LCOE of different generating technologies. These parameters were changed independently, and the LCOE was recalculated keeping everything else constant in order to isolate and compare their relative impact on the LCOE.

While the vertical axis denotes the Median case value of the LCOE, the horizontal bars indicate the percentage increase or decrease of this value caused by a ±50% variation in the assumptions for discount rate, construction cost, economic lifetime, fuel cost, CO_2 cost, lead time and load factor (for onshore wind and solar PV technologies).

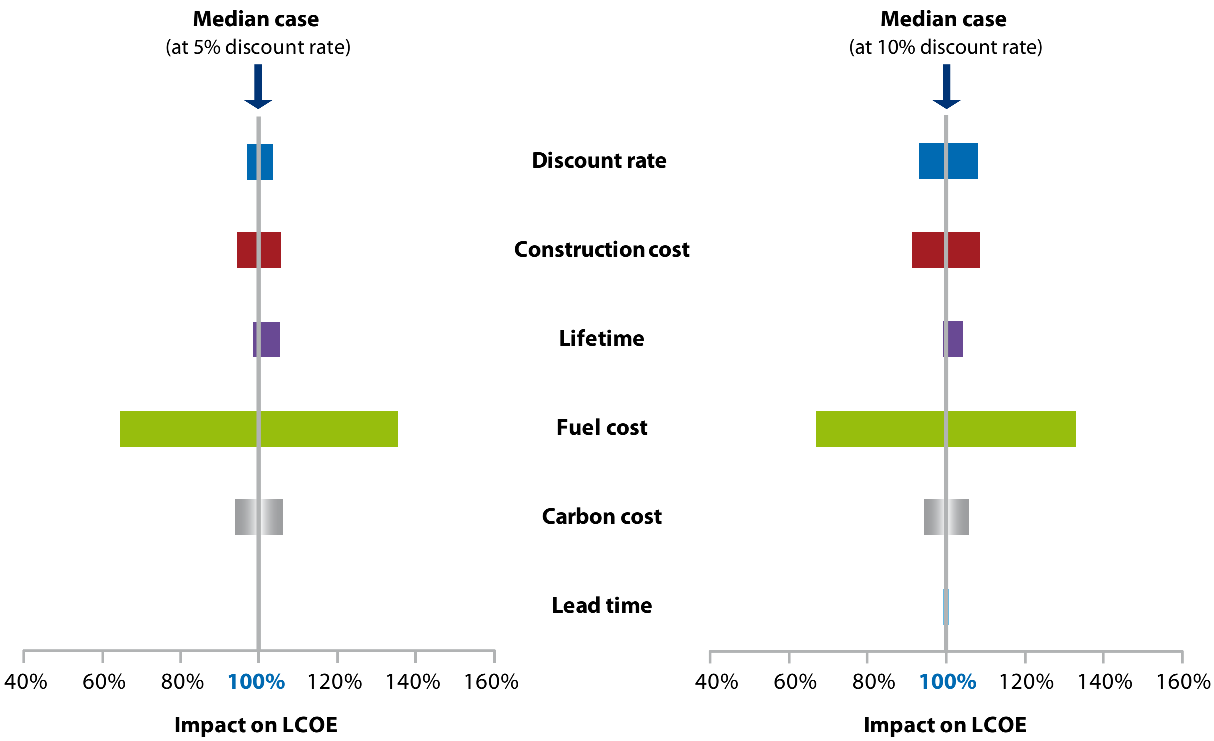
Figure 6.1: Tornado graph 1 nuclear



* Lifetime and LCOE are inversely related, as a lifetime extension results in total levelised cost reduction and a lifetime decrease leads to a generation cost increase.

The economics of nuclear energy are largely dependent on total investment costs,[1] which are determined by both construction cost and the discount rate. At a 5% discount rate, the key driver of the LCOE of nuclear power is construction costs,[2] while at 10%, discount rates have a larger impact on the LCOE than any other parameter. A reduction in lead time also has a significant impact on total costs, in particular at a 10% discount rate due to increased interest during construction (IDC). Construction delays, on the other hand, have a lower impact on costs, provided the total budget remains constant, which is generally an unrealistic assumption. In practice, cost delays often entail cost overruns. Early retirement of a nuclear plant has a greater effect on total LCOE than its lifetime extension beyond 60 years, mainly due to the discounting effect. Finally, given the small share of fuel cost in total cost, variations on nuclear fuel prices and services have the least impact on total LCOE.

Figure 6.2: Tornado graph 2 gas

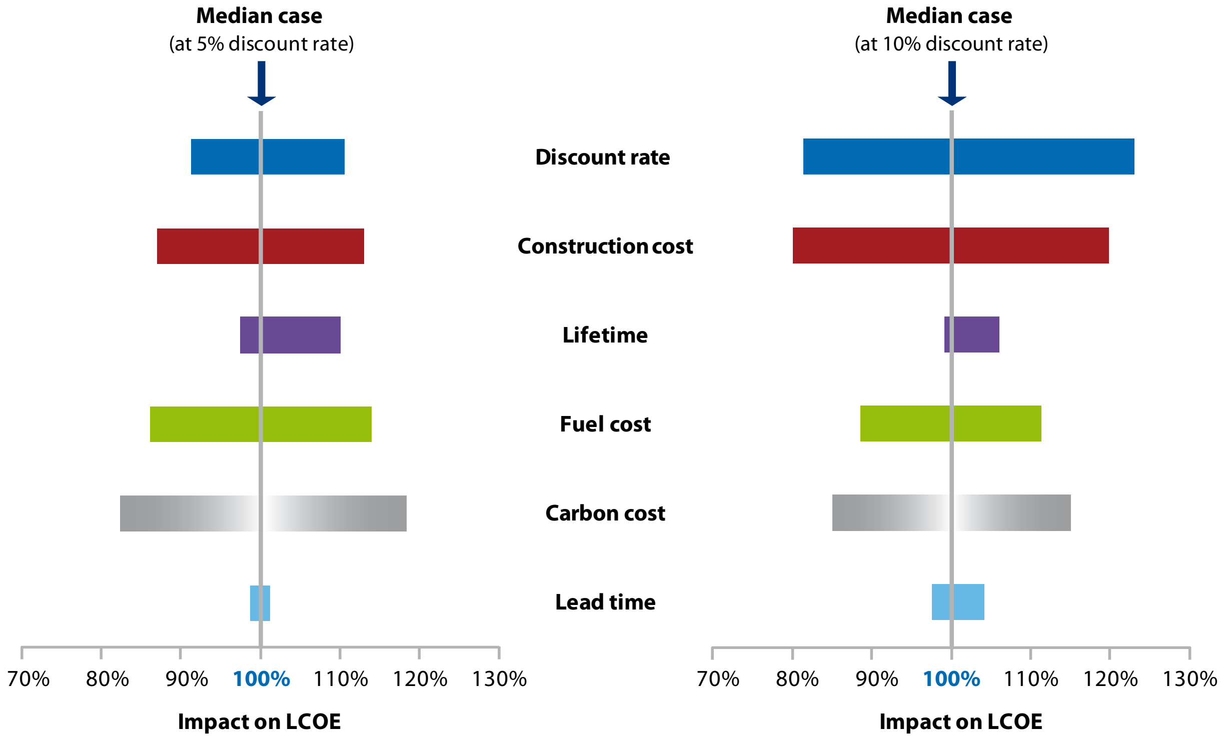


For gas, the picture is reversed. At any discount rate, the fuel cost is by far the single most important cost parameter affecting the LCOE of gas-fired plants. At a 5% discount rate, the carbon cost is the second most important cost determinant, closely followed by construction costs, while variations in the discount rate have the least impact of all parameters on total costs. At a 10% discount rate, construction cost followed by discount rates is the most important parameter after fuel costs. At both discount rates, early retirement of the plant has a larger impact than a comparable life extension.

1. Total investment costs include both overnight costs (construction costs and contingency costs) and interest during construction (IDC).

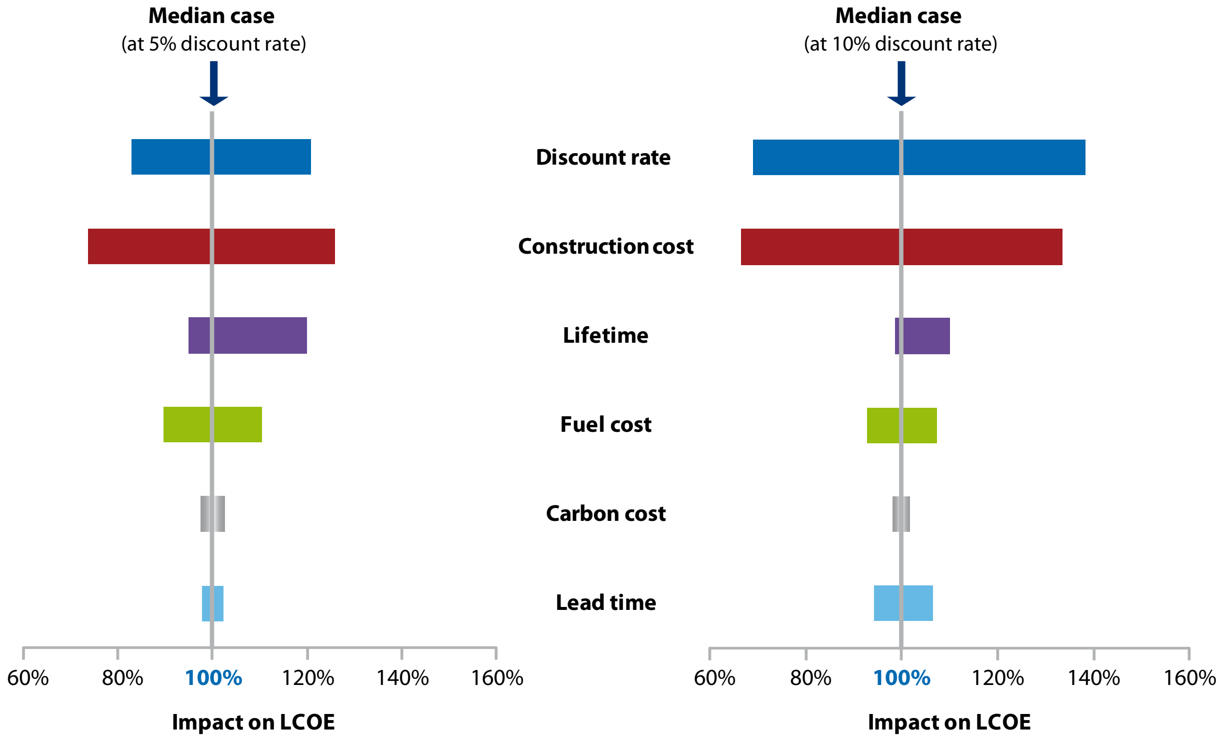
2. Construction costs include owner's and EPC costs but exclude contingency and IDC.

Figure 6.3: Tornado graph 3 coal



In the case of coal-fired capacity, the picture is mixed. The key cost drivers differ depending on the discount rate case. In the low discount rate case, variations in carbon costs have the largest impact on total costs, while in the high discount rate case construction cost is the key determinant of the total LCOE of coal-fired plants. In particular, with a CO_2 price of USD 30/tonne, at a 5% discount rate, the most important cost driver for coal plants is the cost of emitting CO_2, followed by fuel costs. In contrast, at 10%, variations in the discount rate have the largest impact on total LCOE, closely followed by construction costs. Again, the impact of variations in the lifetime of the plant is markedly asymmetric, with early retirement having a larger impact than a comparable lifetime extension. Lead times have the least impact on the LCOE of coal plants.

Figure 6.4: Tornado graph 4 coal with CC(S)



In the case of coal-fired plants with CC(S) the picture is also relatively balanced. As for nuclear, having additional investment costs compared to plants without CC(S), construction costs and discount rates are by far the most important cost drivers for these plants. At a 5% discount rate, construction costs predominate, while at 10% the discount rate has a greater impact. Obviously, with 90% carbon capture equipment, for plants with CC(S), CO_2 is no longer an important cost component. On the other hand, despite the efficiency loss that carbon capture entails, fuel costs for these plants have a relatively lower impact than other cost parameters on total LCOE and comparatively lower than in the case of coal-fired plants without CC(S). This is on the one hand due to the much higher capital investment requirements in plants with CC(S), which dilute the impact of fuel costs on total costs, and, on the other, the fact that the median value for fuel costs retained in the Median case from the sample of reported plants with CC(S) is lower than for other coal plants, as CC(S) plants are more likely to be built in those countries where cheap domestic coal supplies are available, rather than in coal-importing countries, which is reflected in this study's sample.

Figure 6.5: Tornado graph 5 onshore wind

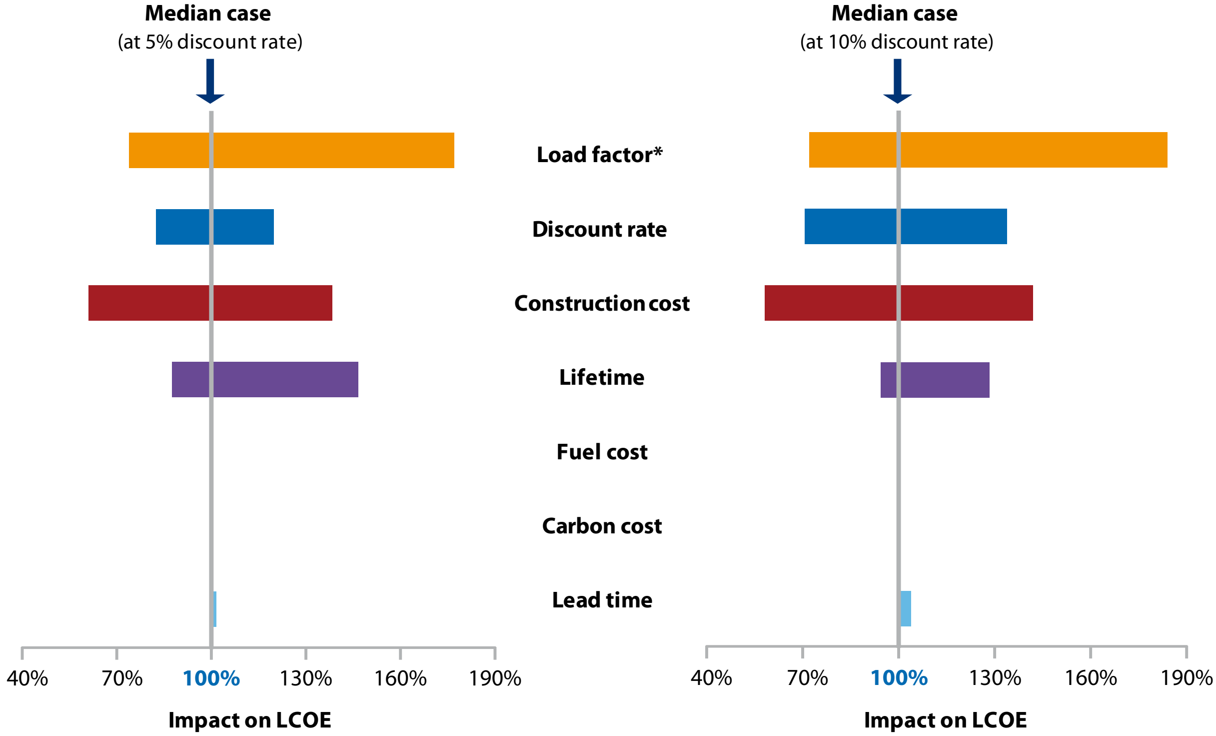
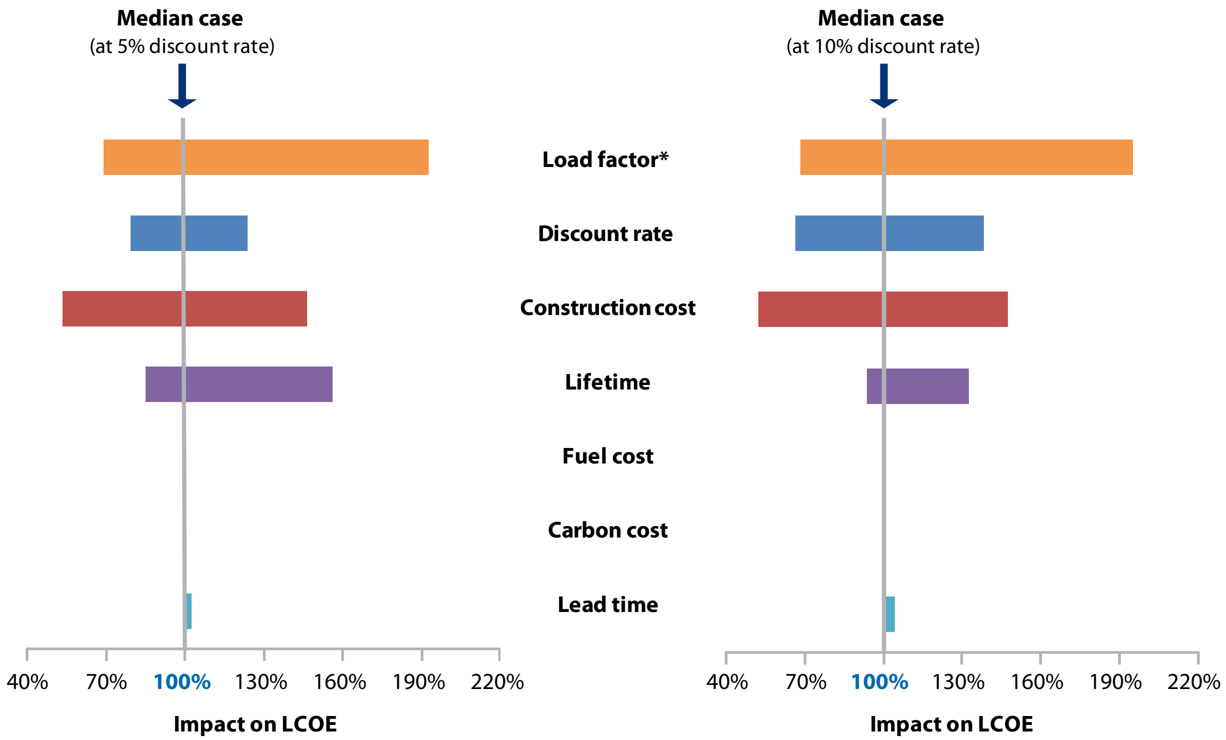


Figure 6.6: Tornado graph 6 solar PV



* Load factor and LCOE are inversely related. A higher load factor results in a reduction of LCOE and a lower load factor results in an increase of LCOE.

The levelised costs of electricity produced with onshore wind and solar PV technologies exhibit a very high sensitivity to load factor variations, and to a lesser extent to construction costs, at any discount rate. The impact of variations in capacity factors is also markedly skewed to the right, meaning that plants are particularly sensitive to decreases in the load factor. Construction cost is the second most important parameter affecting the competitiveness of renewable plants. For certain renewable technologies, namely for solar PV (as a result of learning rates, cost-reducing manufacturing and technology improvements), substantial cost reductions are expected in the coming years.

At a 5% discount rate, for wind and solar technologies the operating lifetime of the plant is the next most important cost driver, after capacity factor and construction cost, with early retirement of plants having a far greater impact than life extension on total LCOE. At a 10% discount rate, the impact of further variations in the cost of capital weighs more heavily than variations in the operating lifetime of the plant. Given the short construction times and relatively modest up-front investment compared to other generation plants, IDC is a relatively minor cost component and, despite the high capital-cost ratio, lead times become the least important cost driver for these technologies at both discount rates.

The analysis confirms that the key cost driver for more capital-intensive technologies,[3] especially those with long lead times such as nuclear power and CC(S), is the discount rate. In contrast, variable costs are the main determinant of the cost for fossil-fired plants. The generation costs of gas-fired plants are highly sensitive to variations in fuel costs, above all other parameters, and to a greater extent than other fossil-fuelled plants. For coal-fired plants, construction costs are less important determinants of the LCOE than the variable cost of fuel and CO_2 when using a 5% discount rate; however, with a 10% discount rate investment costs overshadow variable fuel and CO_2 costs. This is also applicable to coal-fired plants with CC(S) except for CO_2 cost which is no longer an important parameter in these plants. Finally, despite capital costs accounting for a large share of total LCOE in renewables plants, given their short lead times, these technologies are, among the capital-intensive technologies, the least sensitive to variations in discount rates. Load factors, which are fixed for baseload technologies (with the load factor kept constant at 85%), are of utmost significance for renewable generation sources.

3. All electricity generation technologies are broadly speaking capital-intensive. However, nuclear and coal plants involve much higher relative upfront investment costs and longer lead times than other technologies. Although much lower, gas-fired plants still require significant up-front investment although, on a per MWh basis, variable fuel costs far outweigh capital costs in total costs. Total capital investment in wind or solar farms depends on the plant size, which can vary from very small (< 1 MW) to utility scale (> 100 MW); in any case, as renewable electricity generation does not involve any fuel or CO_2 cost, capital costs account for most (nearly all) of total costs. See the qualitative discussion on discount rates in section 6.3.

6.2 Summary results of the sensitivity analyses for different parameters

The different impact of the selected parameter on each generation technology can be partly explained by the different cost structure they present. The table below summarises the relative weight of each cost component at both 5% and 10% discount rates for each of the main technologies considered in the Median case.

Table 6.2: Total generation cost structure

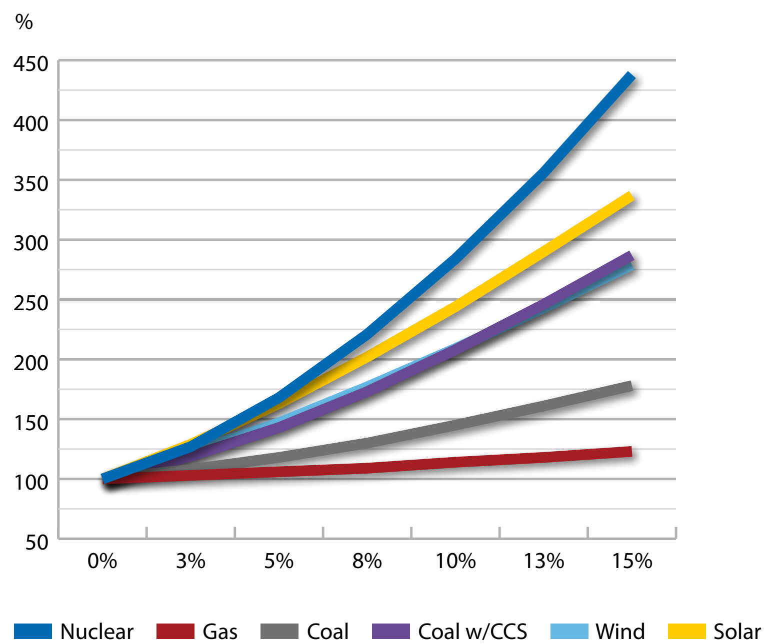
	at 5%						at 10%					
	Nuclear	Coal	Coal w/CCS	Gas	Wind	Solar	Nuclear	Coal	Coal w/CCS	Gas	Wind	Solar
Total Investment cost	58.6%	25.9%	51.6%	11.1%	76.5%	91.7%	75.6%	39.8%	66.8%	17.3%	83.8%	94.9%
O&M	25.2%	9.2%	21.9%	5.2%	22.7%	7.3%	14.9%	7.5%	15.1%	4.9%	16.0%	4.9%
Fuel costs*	16.0%	27.9%	21.0%	71.3%	0.0%	0.0%	9.5%	22.8%	14.5%	66.4%	0.0%	0.0%
CO_2 costs	0.0%	36.8%	5.2%	12.3%	0.0%	0.0%	0.0%	29.9%	3.6%	11.4%	0.0%	0.0%
Decommissioning	0.3%	0.1%	0.2%	0.1%	0.8%	1.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.3%

*Fuel costs for nuclear comprise the costs of the full nuclear fuel cycle including spent fuel reprocessing or disposal.

6.2.1 Discount rates

The significant impact of discount rates on total generation costs for most technologies can be seen from the sensitivity analysis that was performed for discount rates ranging from 2.5% to 15%.

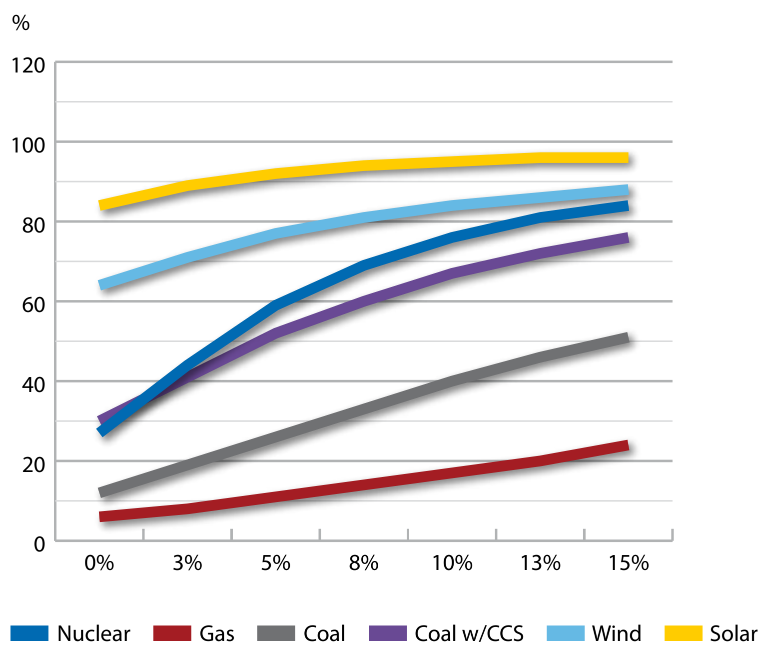
Figure 6.7: LCOE as a function of the discount rate



Logically, with an increased cost of capital the total generation cost for all technologies increases. The first observation is the relative stability of the cost of gas-fired power and hence its relative insensitivity to discount rate changes. At the other end of the spectrum, nuclear power, despite having a lower investment cost ratio than renewable technologies, is the most sensitive technology to discount rate changes, due to the fact that it has longer construction times than any other technology. Higher discount rates also lower the benefit from longer operating lifetimes of nuclear power plants. Hence, the structure and cost of financing is of considerable importance to investments in nuclear capacity. Coal-fired power plants with CC(S) have higher up-front investment costs and longer lead times relative to coal-fired plants without CC(S), so they are the most sensitive among fossil-fuelled plants to discount rates.

It is also interesting to compare the impact of discount rates on the relative capital intensity of different technologies. The graph below shows that the ratio of investment costs to total costs for nuclear power rises quicker than the one for solar or wind, even though renewable technologies initially have a much higher investment costs to total cost ratio. Indeed, capital cost ratios over total LCOE for solar and wind are relatively insensitive to discount rate variations compared to other technologies, even gas-fired plants for which capital costs only account for a much smaller share of total LCOE. The reason is that renewable technologies have substantially shorter construction times than any other technology. The important cost item of interest during construction (IDC) thus weighs heavily on total costs for long lead time technologies and that weight becomes not only absolutely but also relatively more important with increasing interest rates.

Figure 6.8: The ratio of investment cost to total costs as a function of the discount rate



The capital intensity of a project matters because it indicates the vulnerability to changes in the output price and/or in demand. For instance, if electricity prices suddenly fell below LCOE and investors would have to give up hope of recouping their investments, investors with a low fixed cost/total cost ratio (think of a gas-fired power plant) could check their losses and leave the market with limited financial damage. An investor with a high fixed cost/total cost ratio (think of a nuclear power plant or renewable energy) would have to absorb relatively much higher losses. Although they would continue to produce and earn (low) revenue, a comparatively large portion of their investments would need to be written off.

The working of electricity markets thus has a large impact on the structure of the technology choices of investors. At comparable levels of LCOE and at comparable volatility of variable inputs, the more volatile electricity prices, the more investors will tend towards technologies with low fixed cost/total cost ratios such as gas, and to a lesser extent, coal. High fixed cost technologies such as nuclear, renewables, or coal with carbon capture and storage (CCS) are particularly vulnerable to electricity price volatility.

6.2.2 Fuel costs

Fuel cost is a key component of the total cost of generating electricity from certain technologies, namely fossil fuelled. Renewable technologies, like hydro, wind or solar, have no fuel costs, and this is one of the main competitive advantages of these technologies. *Projected Costs of Generating Electricity* assumes a stable reference fuel cost [4] for all OECD countries of USD 90/t for steam coal and USD 10.3/MMBtu for natural gas imports in Europe (USD 11.09/MMBtu in Asia) [5], broadly in line with WEO 2009 fuel price assumptions in the Reference and 450-ppm Scenarios. Lower prices for coal and gas were assumed for large, domestic producers of these fuels (Australia, Mexico and United States). Finally, for nuclear power, the generic assumption for front-end nuclear fuel cost is 7 USD/MWh [6] (a low and stable fuel price being a major advantage of nuclear power).

Table 6.3: 2009 WEO fossil fuel price assumptions in the Reference Scenario (2008 USD per unit)

		Unit	2000	2008	2015	2020	2025	2030
Real terms (2008 prices)								
IEA crude oil imports		barrel	34.30	97.19	86.67	100.00	107.50	115.00
Natural gas imports	United States	MBtu*	4.74	8.25	7.29	8.87	10.04	11.36
	Europe	MBtu	3.46	10.32	10.46	12.10	13.09	14.02
	Japan LNG	MBtu	5.79	12.64	11.91	13.75	14.83	15.87
OECD steam coal imports		tonne	41.22	120.59	91.05	104.16	107.12	109.40

*Million British thermal units.

Table 6.4: 2009 WEO fossil fuel price assumptions in the 450 Scenario (2008 USD per unit)

								% difference from reference scenario	
	Price	Unit	2008	2015	2020	2025	2030	2020	2030
Crude oil	IEA import price	barrel	97.19	86.67	90.00	90.00	90.00	-10%	-22%
Natural gas imports	United States	MBtu*	8.25	7.29	8.15	9.11	10.18	-8%	-10%
	Europe	MBtu	10.32	10.46	11.04	11.04	11.04	-9%	-21%
	Japan	MBtu	12.64	11.91	12.46	12.46	12.46	-9%	-21%
Steam coal	OECD imports	tonne	120.59	85.55	80.09	72.46	64.83	-23%	-41%

*Million British thermal units.

Note:
WEO price assumptions extend to only 2030 and increase over the period 2010-2030. They also vary for different regions in the case of gas.

Source: IEA, *World Energy Outlook,* 2009.

This section tests the sensitivity of the LCOE calculated at the two discount rates, 5% and 10%, to doubling and halving fuel costs for fossil-fired and nuclear [7] power plants. Figures 6.9 and 6.10 illustrate the sensitivity of the LCOE of these technologies to +/-50% variations in fuel costs. The LCOE of 100% corresponds to the Median Case generation cost for different technologies.

4. For the purposes of the EGC study, fossil fuel prices and nuclear cycle fuel costs are an exogenous determinant of the cost of generating electricity. They should not be seen as forecasts.

5. Million British Thermal Units (MMBtu) is a common unit of energy for natural gas. One tonne of coal equivalent (tce) corresponds to 27.78 MMBtu. Fuel prices are assumed to remain flat over the entire lifetime of the plant.

6. Nuclear fuel costs are composed of the costs for uranium, enrichment and conversion, and fuel fabrication in roughly equal parts.

7. In the case of nuclear power plants, the changes affect only the front-end fuel costs.

Figure 6.9:
LCOE as a function of fuel cost variation
(at 5% discount rate)

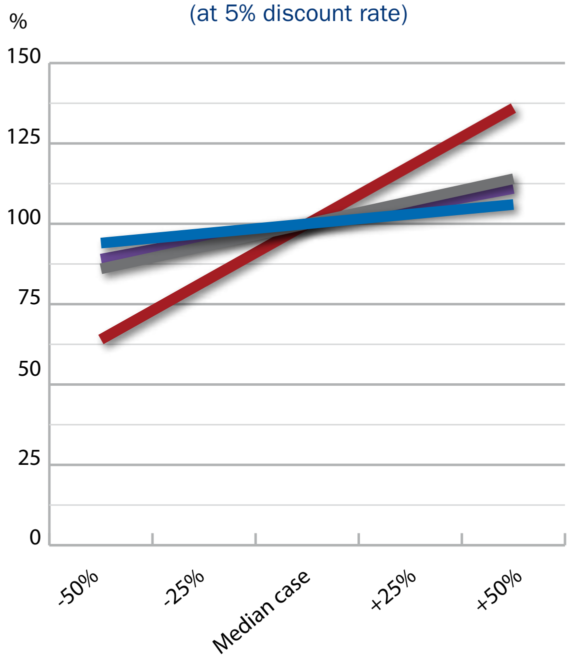
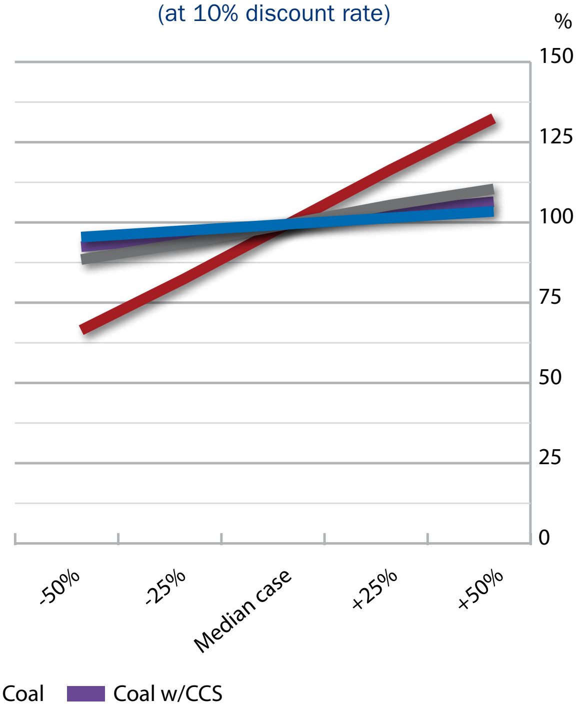


Figure 6.10:
LCOE as a function of fuel cost variation
(at 10% discount rate)



Figures 6.11 and 6.12 show the share of fuel costs in total LCOE for these technologies as a function of different fuel costs levels (halving and doubling median fuel cost) which can be thought of as an indicator of the exposure of each technology to the underlying fuel price risk. The results are summarised below.

Figure 6.11:
Share of fuel cost over total LCOE calculated
(at 5% discount rate)

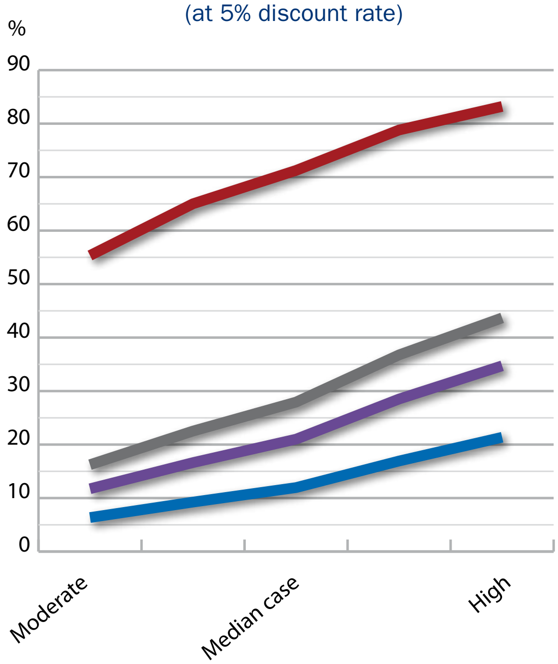
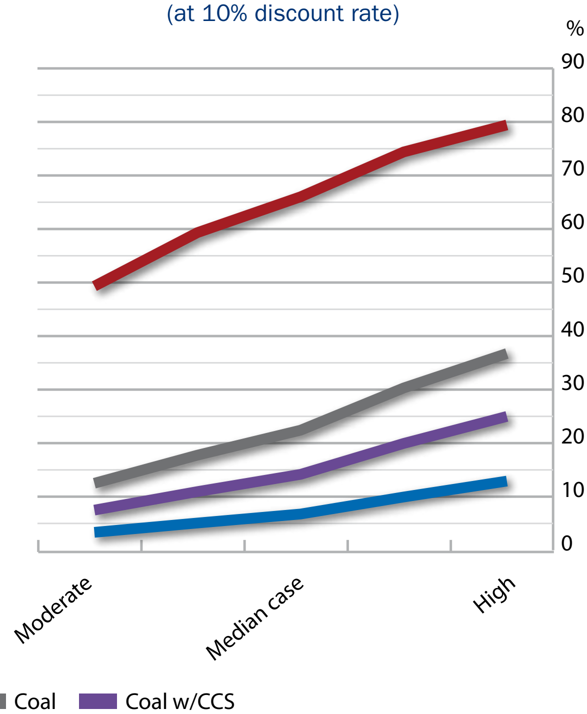


Figure 6.12:
Share of fuel cost over total LCOE calculated
(at 10% discount rate)



Nuclear generation LCOE changes slightly (+/-6%) with variations in its front-end fuel costs, since the latter represent only a small share of total levelised costs, around 12% in the low discount rate case and 7% in the high discount rate case. Halving total front-end nuclear costs [8] brings their share down to around 6% and 4% of the total LCOE in the low and high discount rate scenarios respectively; doubling nuclear fuel costs increases the share of fuel costs in total LCOE to 21% and 13% respectively. Low degree of exposure to the fuel price risk is one of the advantages of nuclear energy.

Gas-fired plants are, on the other hand, very sensitive to fuel cost fluctuation (the LCOE varies +/-36% with +/-50% variations in fuel costs). Fuel costs represent between 66% and 71% of total levelised costs of CCGTs in the Median Case, depending on the discount rate used. This is an important drawback for CCGTs as a 50% increase in the fuel cost augments the electricity generating cost by more than a third. Doubling the median fuel cost for gas plants increases its share in total levelised costs up to 80% of the LCOE of a CCGT in the high discount rate case and to 83% in the low discount rate case. On the other hand, a two-fold decrease in its fuel cost reduces the share of fuel in total costs to around 50%-55%, at 10% and 5% discount rate respectively.

Coal-fired plants are also more sensitive to fuel costs than nuclear power, but less so than CCGTs (+/-14%), since fuel costs represent in the Median case between 23%-28% (at 10% and 5% discount rate respectively) of total costs for a supercritical/ultra supercritical plant. The share of fuel cost over total LCOE in different fuel price scenarios (halving and doubling) ranges from 13%-37% when calculated at high discount rate and from 16%-44% at low discount rate. Coal plants with carbon capture facilities are less sensitive to fuel cost variations than coal without carbon capture (+/-11%); this despite the loss of thermal efficiency, since the relative impact of the fuel cost increase on the total LCOE is offset by the higher share of construction costs in total costs.[9] For coal plants with CC(S) the share of fuel costs on total LCOE varies from 21% in the low discount rate to 14% in the high discount rate. Halving total costs brings their share down to around 12% in the low discount rate and 8% in the high discount rate. Their share rises to 35% in the low discount rate and to 25% in the high discount rate when doubling fuel costs.

8. Halving and doubling only the price of raw uranium translates into a more modest variation in the nuclear fuel cost.

9. For coal-fired plants equipped with carbon capture, the efficiency loss of CC(S) is assumed to be 10% at the beginning of its commercial deployment (by 2020) and 7% beyond 2025. The Median Case assumes a generic thermal efficiency of 35.5% compared to 42% for the median supercritical/ultra supercritical plant.

6.2.3 Carbon costs

Contrary to fossil-fuelled generation, nuclear and renewable energy (hydro power, wind, solar) plants produce no CO_2 emissions. Although not singled out in the sensitivity analysis, CHP, biomass and distributed generation also have clear advantages over coal and gas-fired plants in terms of CO_2 emissions. Coal-fired technologies have the highest carbon intensity, roughly double those of CCGTs, and therefore prove to be most sensitive to the carbon cost variation, as can be seen from the sensitivity analysis below.[10]

Figures 6.13 and 6.14 illustrate the sensitivity of the LCOE of different fossil-fired technologies to CO_2 costs. The LCOE of 100% corresponds to the Median Case generation costs for fossil-fired technologies.

Figure 6.13:
LCOE as a function of carbon cost variation
(at 5% discount rate)

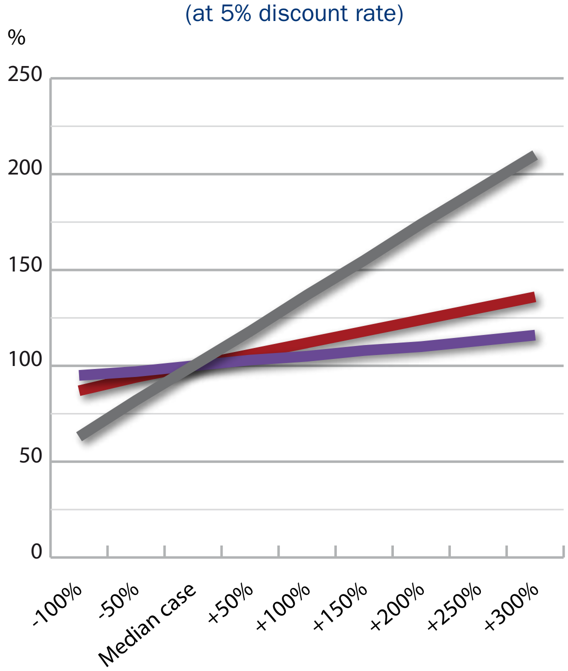
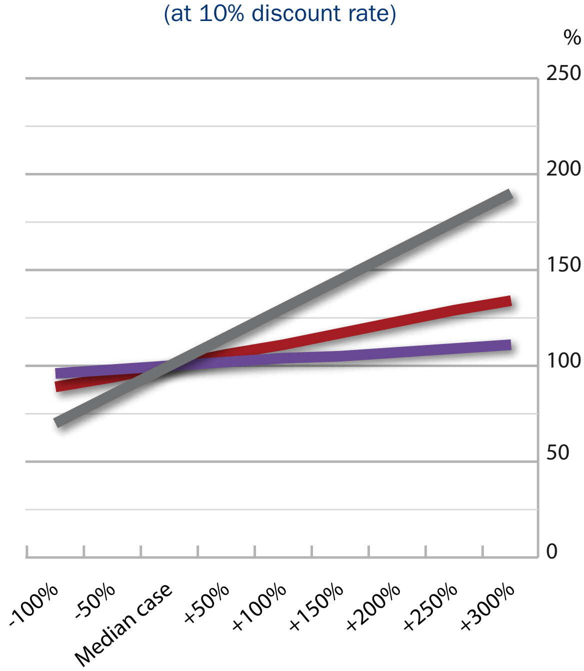


Figure 6.14:
LCOE as a function of carbon cost variation
(at 10% discount rate)



Gas Coal Coal w/CCS

A +/-50% variation in carbon costs translates into a +/-18% variation in the total LCOE of coal-fired plants while the same variation just changes the total LCOE of a gas-fired plant by +/-6%. The least sensitive to carbon cost variations are, as one would expect, coal plants equipped with carbon capture technology [11] due to the low share of carbon cost in total LCOE. An equivalent +/-50% change in carbon costs only has a +/-3% impact on its total LCOE.

10. In the absence of country specific data, CO_2 intensity of coal is assumed at 0.77 tCO_2/MWh; for gas CCGT it is assumed to be 0.35 tCO_2/MWh, using values from 2006 IPCC guidelines for National Greenhouse Gas Inventories, Chapter 2 «Stationary Combustion», p. 2.16.

11. CC(S) plants are assumed to capture 90% of CO_2 emissions. The LCOE for CC(S) only takes into account the additional cost of carbon capture and compression but not that of CO_2 transportation and storage.

Figures 6.15 and 6.16 show the share of carbon costs in total LCOE for different fossil-fired technologies as a function of different CO_2 cost levels which can be thought of as an indicator of the exposure of each of these technologies to CO_2 price risk.

Figure 6.15: Share of CO_2 cost over total LCOE calculated

(at 5% discount rate)

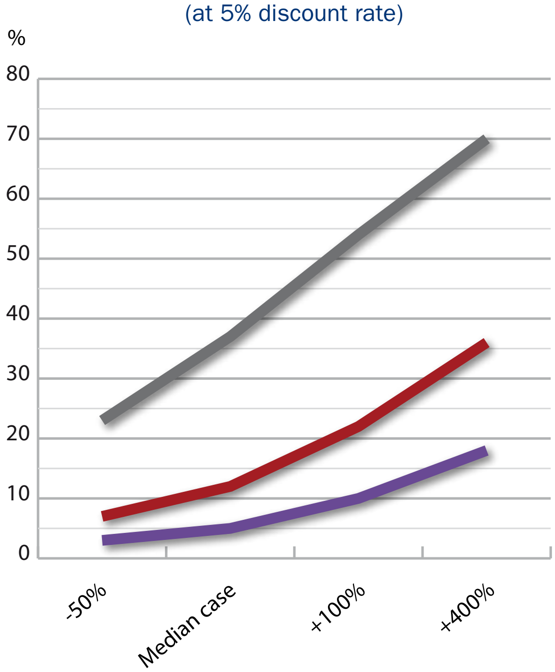
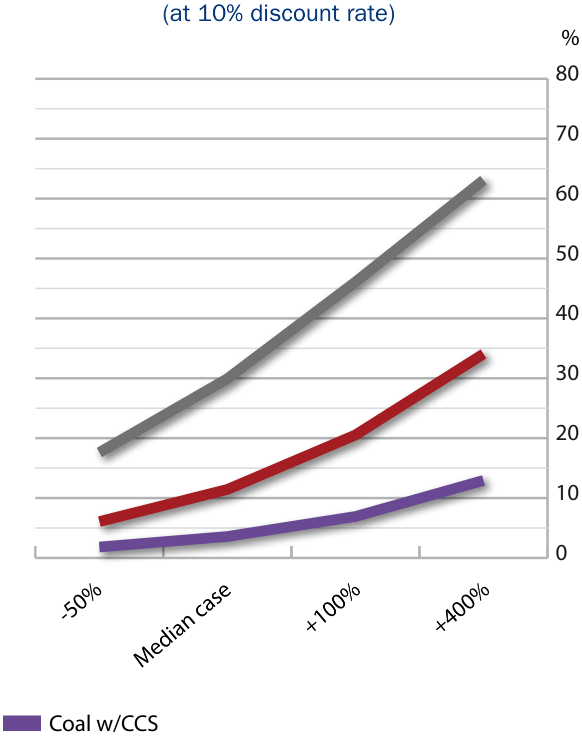


Figure 6.16: Share of CO_2 cost over total LCOE calculated

(at 10% discount rate)



Coal-fired generation is very sensitive to the variation in carbon costs since they represent a significant share of the total LCOE: in the Median Case, 37% when calculated at a 5% discount rate, and 30% when using a 10% discount rate. The contribution of carbon costs to the LCOE produced from gas-fired plants in the Median Case is only 12% at a 5% discount rate and 11% at a 10% discount rate. This makes the costs of gas-fired electricity generation considerably less sensitive to the variation in carbon costs than coal-fired electricity. For coal plants equipped with carbon capture technology, the contribution of carbon costs is only 4% in the high discount rate case and 5% in the low discount rate case. This means they could become an alternative to coal-fired generation without carbon capture if carbon costs are sufficiently high or there remains high uncertainty over future carbon prices, once carbon capture has been demonstrated on an industrial scale.

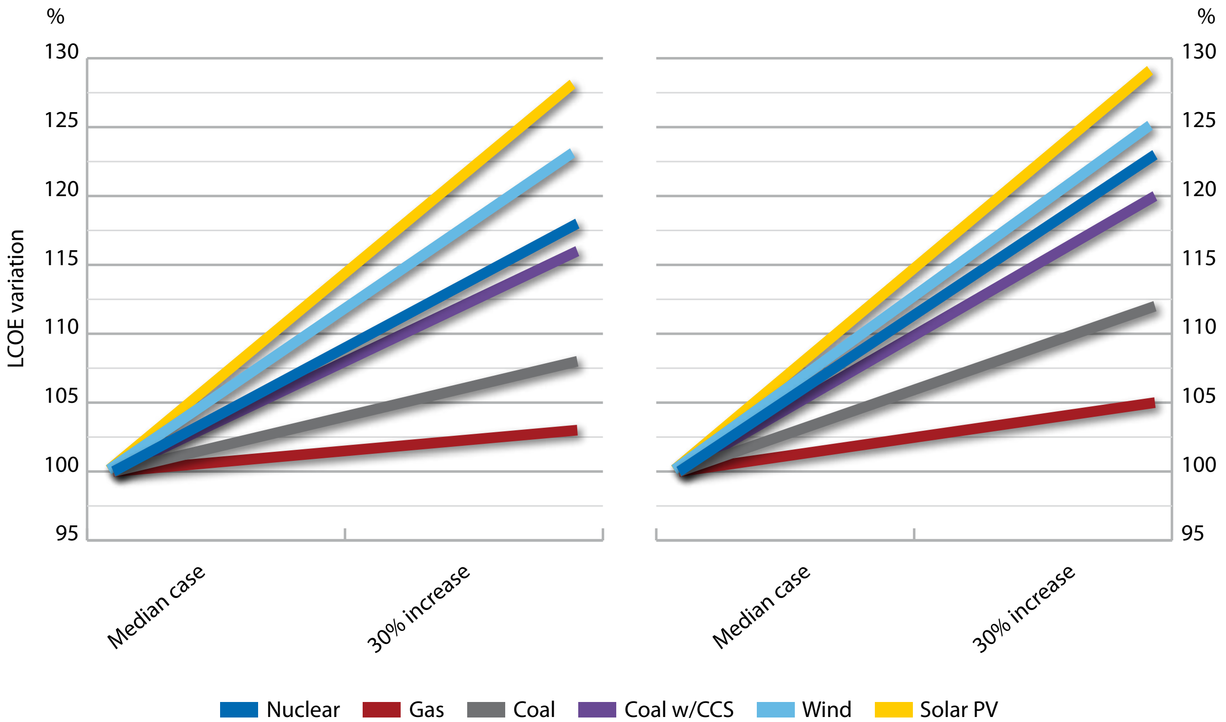
For countries wishing to reduce their power generation sector's carbon footprint there is a portfolio of technologies to choose from and a price of CO_2 emissions can fundamentally change investment decisions. Excluding nuclear power as an option reduces real low-carbon base load generation options. If, in addition, local conditions are unfavourable for renewables (lack of good wind, solar resources or biomass resources or lack of access to back-up generation), the only option to reduce CO_2 emissions is currently a shift from coal to gas. Once new coal plants equipped with CC(S) become available, they may also provide an option for cost-effective low-carbon baseload generation option.

6.2.4 Construction costs and lead times

Electricity generation is generally speaking a highly capital-intensive industry with significant up-front costs. Investment costs are therefore a key component of LCOE. A sensitivity analysis has been conducted to examine the impact of a 30% increase in construction cost on the LCOE of different electricity generation technologies. Figures 6.17 and 6.18 illustrate the impact of such construction cost variation on the levelised costs at 5% and 10% discount rates. 100% on the vertical axis corresponds to the level of the LCOE in the Median case.

Figure 6.17: LCOE as a function of a 30% construction cost increase (at 5% discount rate)

Figure 6.18: LCOE as a function of a 30% construction cost increase (at 10% discount rate)



The marked difference in the construction cost sensitivities of different plant types can be explained by their different cost structures, i.e. share of capital investment, O&M, and fuel and CO_2 costs. Solar PV, for which 85-95% (depending on the discount rate used) of the LCOE corresponds to investment cost, is the technology most sensitive to changes in construction costs, while gas-fired plants are the least sensitive due to their relatively modest share in total LCOE (11-17%). Levelised costs of onshore wind (where investment costs account for 77-85% of total LCOE), nuclear (60-75% of total LCOE) and coal with CC(S) (51-66%) are also very sensitive to the construction cost variation, particularly at a 10% discount rate.

The share of the total investment cost is particularly high in a 10% discount rate environment, representing 95% of solar, 84% of wind, 76% of nuclear, 67% of coal with CCS, 40% of coal without CCS, and 17% of gas-fired electricity generation costs. The cost of generating electricity from solar, nuclear and wind technologies is therefore, as one would expect, more sensitive to the overnight construction cost than the costs of other baseload alternatives.

Another way of testing the sensitivity of different electricity generation technologies to the construction cost variation is to look at construction delays, with the construction period taken here to signify the period of construction starting from the pouring of concrete and ending with the commissioning date (COD), assumed to be 2015.

The results of the sensitivity analysis performed to test whether construction delays have an important bearing on levelised costs are summarised in Figures 6.19 and 6.20. On the vertical axis, 100% corresponds to the LCOE at the Median case construction periods. Note that all other variables are kept fixed in this analysis. In practice this is unlikely; delays are generally accompanied by increased investment costs.

Figure 6.19: LCOE as a function of a variation in the construction period
(at 5% discount rate)

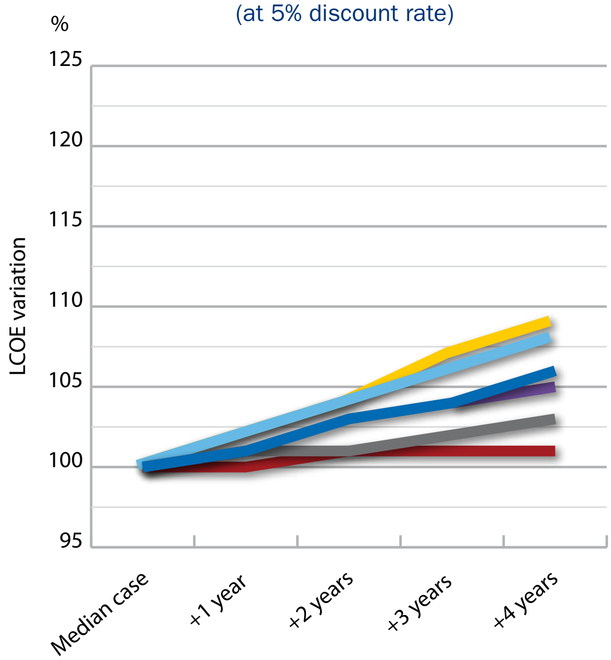
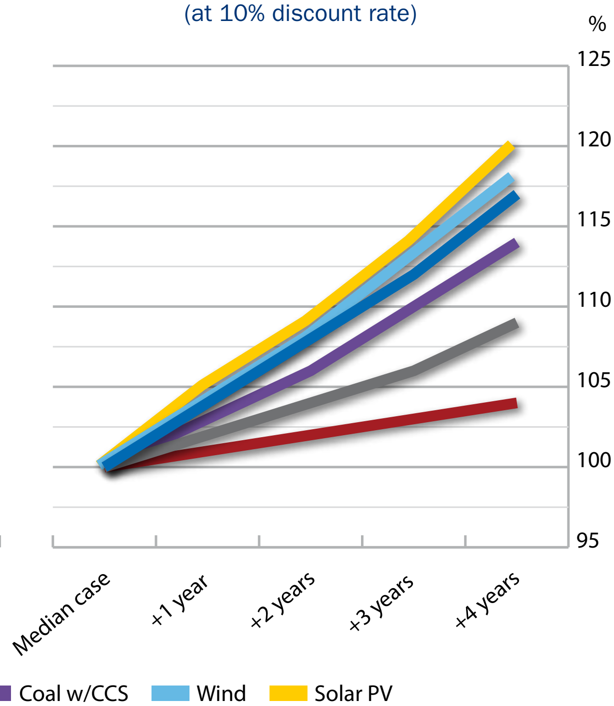


Figure 6.20: LCOE as a function of a variation in the construction period
(at 10% discount rate)



The comparison of the two graphs shows that at a 5% discount rate, construction delays of up to four years have a limited impact on levelised costs across the range of generation technologies. More capital-intensive technologies, namely nuclear and coal, with and without CC(S), for which IDC represents a significant cost component [10% of total overnight costs for nuclear and coal and 13% for coal with CC(S)], demonstrate higher sensitivity to lengthier lead times, especially at a 10% discount rate. The impact of construction cost delays is lowest for wind and solar and for gas-fired generation, given that the share of IDC in their respective cost structure is relatively modest (4% of total overnight costs for solar and 5% for wind and gas) so they are the least-exposed technologies to cost overruns due to delays in construction. Note that construction costs are assumed to be uniformly spread over the construction period. When this is not the case, for instance in the construction of certain nuclear plants where most construction expenditure is in the last four to five years, the impact on cost will be lower than shown in this analysis.

6.2.5 Load factors

The load factor of a power plant indicates the ratio of the electrical energy produced by a plant and the theoretical maximum that could be produced at non-interrupted power generation. The load factor is of considerable importance for the economics of power generation, since it defines the amount of electricity produced per unit of generating capacity that will earn revenues to cover both the capital and the operating costs of a power plant.

A sensitivity analysis has been conducted to test the sensitivity of generation costs of different technologies to the load factor variation. Figures 6.21 and 6.22 illustrate the evolution in the levelised costs of generating technologies as a function of load factor variation at 5% and 10% discount rates. On the vertical axis, 100% corresponds to the levelised costs of nuclear, coal and gas-fired plants at 85% load factor (generic study assumption), and to levelised costs of solar PV and wind at 25% load factor.

Figure 6.21: LCOE as a function of a variation in the load factor
(at 5% discount rate)

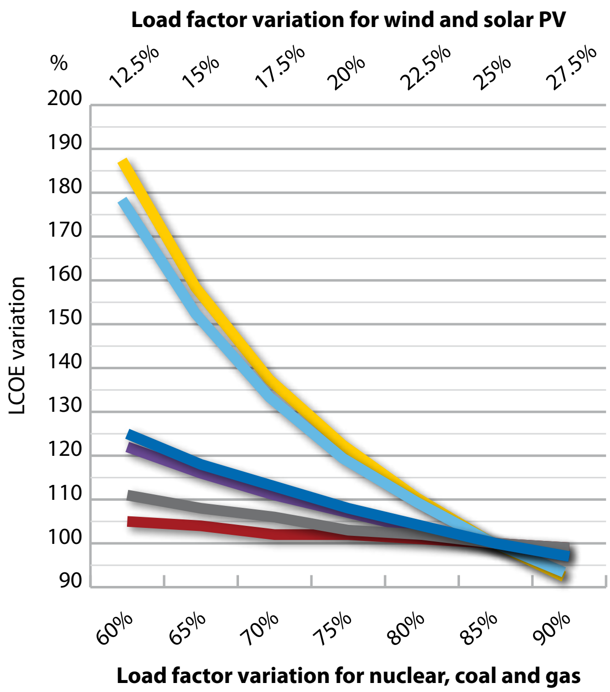
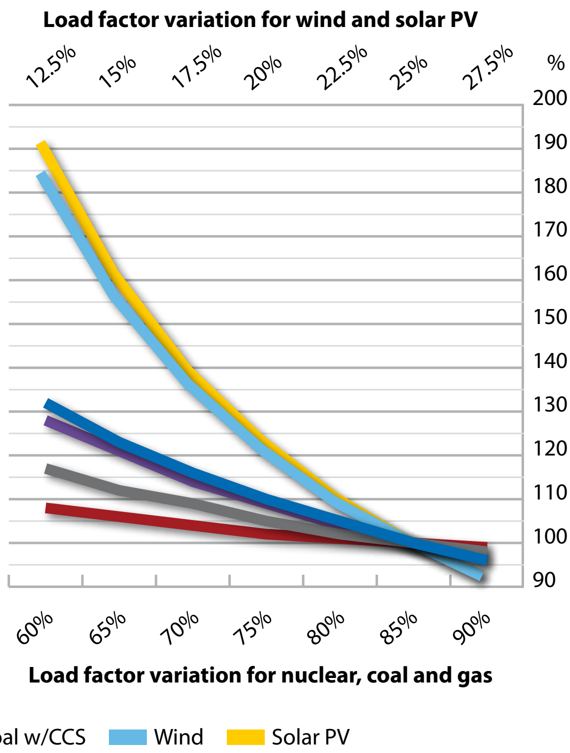


Figure 6.22: LCOE as a function of a variation in the load factor
(at 10% discount rate)



Because nuclear and coal with CC(S) have much higher fixed costs than alternative fossil-fuelled baseload generating technologies, their total LCOE is most affected by the load factor variation, in particular at a 10% discount rate, where fixed costs weigh more heavily. Variable generation sources, wind and solar PV, where fixed costs constitute an even higher share of total costs, are logically even more sensitive to the variation of load factor. Of all generating technologies, gas, where variable costs weigh most in total costs (fuel and CO_2 costs together account for between 78% and 84% of total LCOE, depending on the discount rate), is the least affected by the load factor variation. In other words, running or not running a gas plant makes a much smaller difference to the profitability of a project (due to the high variable costs of gas) than running or not running a nuclear, wind or solar power plant since all three must resolutely cover their high fixed costs, while their variable costs are very low.

6.2.6 Lifetimes

The expected economic lifetime of operation differs among generating technologies. The generic study assumptions hold that nuclear plants last up to 60 years, gas-fired plants around 30 years, coal-fired plants 40 years, and wind and solar PV 25 years. The sensitivity tests have been performed by varying Median case lifetimes by ± 25% and ±50%. The results of the sensitivity analysis are summarised in Figures 6.23 and 6.24. On the vertical axis, 100% corresponds to the LCOE at the Median case operational lifetimes.

Figure 6.23:
LCOE as a function of lifetime variation
(at 5% discount rate)

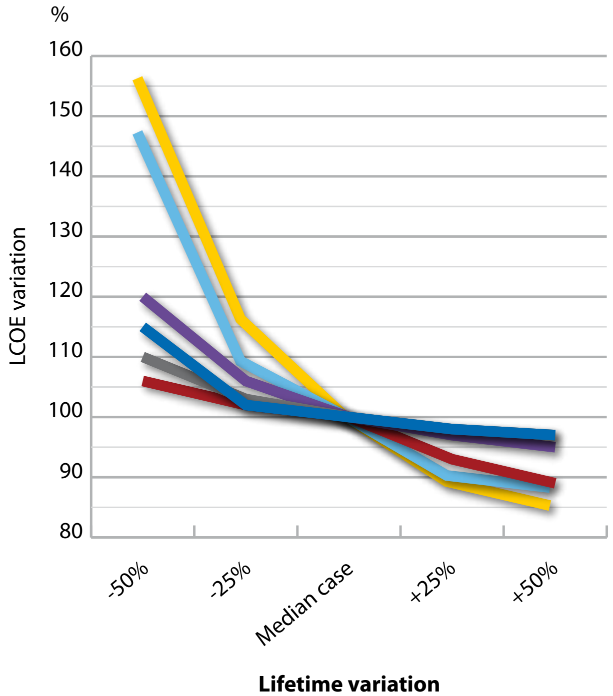
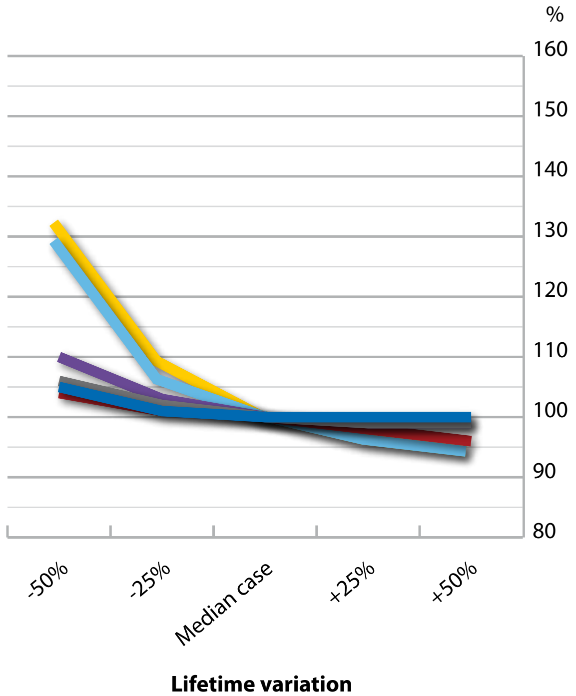


Figure 6.24:
LCOE as a function of lifetime variation
(at 10% discount rate)



The most important conclusion than can be drawn from this analysis is the marked asymmetric impact on total LCOE of early retirement of plants compared to lifetime extensions at both discount rates. While early retirement significantly increases the total LCOE, lifetime extensions have little or no impact on total levelised costs. This is true for all technologies, although the effect is more pronounced for those technologies that have shorter operating lifetimes. Once the plant has been commissioned, and the bulk of the investment cost has been incurred, an early retirement of the plant significantly affects its ability to pay back the initial capital investment. In contrast, in the case of lifetime extensions, once the plant has already recovered the initial capital investment over the original payback period, further extensions will naturally generate additional revenues for the plant; however, due to the discounting effect, revenues accruing far ahead in the future have little impact on LCOE after being discounted.

Also due to the discounting effect, at both discount rates, technologies with longer lifetimes are less affected by relative variations in the operating lifetime of the plant. For example, despite its high up-front costs, which need to be recovered with the revenues produced over the entire lifetime, any extension of the lifetime of a nuclear power plant beyond 60 years has very little impact on the LCOE once costs and revenues for the concerned period are discounted.

Indeed, beyond 40 years, which is the operating lifetime assumed for coal plants, any variation of this parameter has little impact on total LCOE. Levelised costs of electricity produced by solar PV and wind, with shorter lifetimes, are on the other hand the most affected by the variation in the lifetime of the plant. The least affected technology is gas-fired generation, which, with an initial lifetime of 30 years and thanks to the lower proportion of fixed costs, shows relatively stable generation costs as its operational lifetime varies by 25% and 50%.

6.3 Qualitative discussion of different variables affecting the LCOE

The various sensitivity analyses presented in the previous sections highlight the extent to which variations in key cost parameters affect the LCOE. The present section discusses the main drivers and factors affecting those parameters.

6.3.1 Discount rates

Electricity generation is generally a capital-intensive industry, in the sense that it requires very high capital investment which creates a natural barrier to entry into the market. In addition, once incurred, most of this capital cost is "sunk". Nevertheless, not all electricity generation technologies have the same cost structure. Nuclear and coal plants have very high up-front overnight costs (USD 5.7 and 1.6 billion respectively in the Median case) and long lead construction times (7 and 4 years respectively in the Median case) which makes IDC a significant cost component (around 600 and 160 million respectively in the Median case). Therefore, only large utilities have the financial strength to undertake such projects. Although much lower, gas-fired plants still require significant up-front investment to enter the market (the cost of a CCGT in the Median case is around USD 500 million). However, the variable fuel cost outweighs capital costs in total costs. In contrast, investment in renewable plants such as wind or solar is relatively modest (USD 100 and 6 million respectively in the Median case). Plant size can be adjusted from very small to very large scale and building times take, depending on the plant size, from 3 months to 1.5 years on average, but in any case IDC is far less important than for baseload technologies. Therefore, in many OECD markets renewable energy is being developed by independent power producers. Nevertheless, while renewable electricity generation does not involve any fuel or CO_2 cost, capital costs account for most (nearly all) of total costs, which makes the cost of capital a key parameter for these investments as well.

In keeping with tradition, this study calculates the LCOE using two *real* discount rates, 5% and 10%, applied to all technologies. In fact, a key limitation of the LCOE is that it does not take into account the different levels of technology-specific risks among the investment alternatives, risks that can be better understood by considering the weighted average cost of capital (WACC). Investment in generation capacity competes with alternatives in global capital markets. Cost of capital can change to a certain extent over time. In particular, the cost of capital for investment in power generation will depend on the relative risk level of a specific investment compared to alternatives. To some degree, technology-specific risks are captured in the concept of the WACC, which indicates the split between debt and equity financing. To the extent that the technology is riskier, the share of more expensive equity financing might be higher, as the risks and returns of investment projects are usually commensurate. The higher the risks, the higher the costs of debt and equity, and the higher the required return on investment. Different technologies and projects will be perceived to have different levels of risk.

Linked to the question of fixed versus variable cost ratios and the resulting differences in vulnerability to price risk is the additional question concerning the absolute size of investments. An investor in an uncertain environment facing the choice between a 500 MW coal plant and two 250 MW gas plants might prefer to invest in a single gas plant, preserving the real option value of not investing in the second plant if prices or demand turn out to be unsatisfactory.[12] Other things being equal, investors thus prefer small, modular units rather than large, bulky ones. However, this issue needs careful framing due to at least two countervailing reasons. First, waiting holds not only value but also costs (the profits foregone while waiting). Never investing has, of course, the highest real option value. Second, there is the issue of increasing returns to scale. Large units with sizeable fixed costs are large because building them at this size is cheaper than building them at smaller sizes. Usually, this is not due to any physical thresholds but due to informational complexities. Highly technical solutions with all the advantages they may bring will thus demand larger units.[13] In the end, the question of size must be evaluated in the context of the specific contingencies of each product – average cost, the level and volatility of present and future prices and the discount rate all have bearing on the final decision.

The analysis of the risk factors that may affect the cost of capital for a particular project is developed in the boundary chapter on the working of actual power markets. More general financing issues, including the current financial context for energy investment as well as the impact of corporate taxes in the cost of financing power plants are analysed in the boundary chapter on financing issues.

6.3.2 Fuel costs

Fuel costs are an important risk parameter for all investments. Although this study assumes stable fuel prices, this should not be interpreted as a prediction of stable energy markets: prices will, in reality, certainly deviate from the study's working assumption, widely at times, in response to fluctuations in supply and demand.

Potential for long-term changes in relative fuel price levels can completely reverse the overall cost picture and therefore affect the profitability of a plant. For nuclear power plants, the fuel price risk is generally much lower than for fossil-fuelled plants, since fuel costs are a small share of total cost. Furthermore, uranium and fuel cycle services can be and generally are bought under long-term contracts. But it is not only the profitability of a coal or CCGT project which is sensitive to coal and gas prices. Other projects like nuclear power and renewable sources are equally sensitive, since a CCGT project may be the alternative investment. If a nuclear project is chosen on the expectation that gas prices will be high, there is an opportunity cost if the gas price then turns out to be lower.

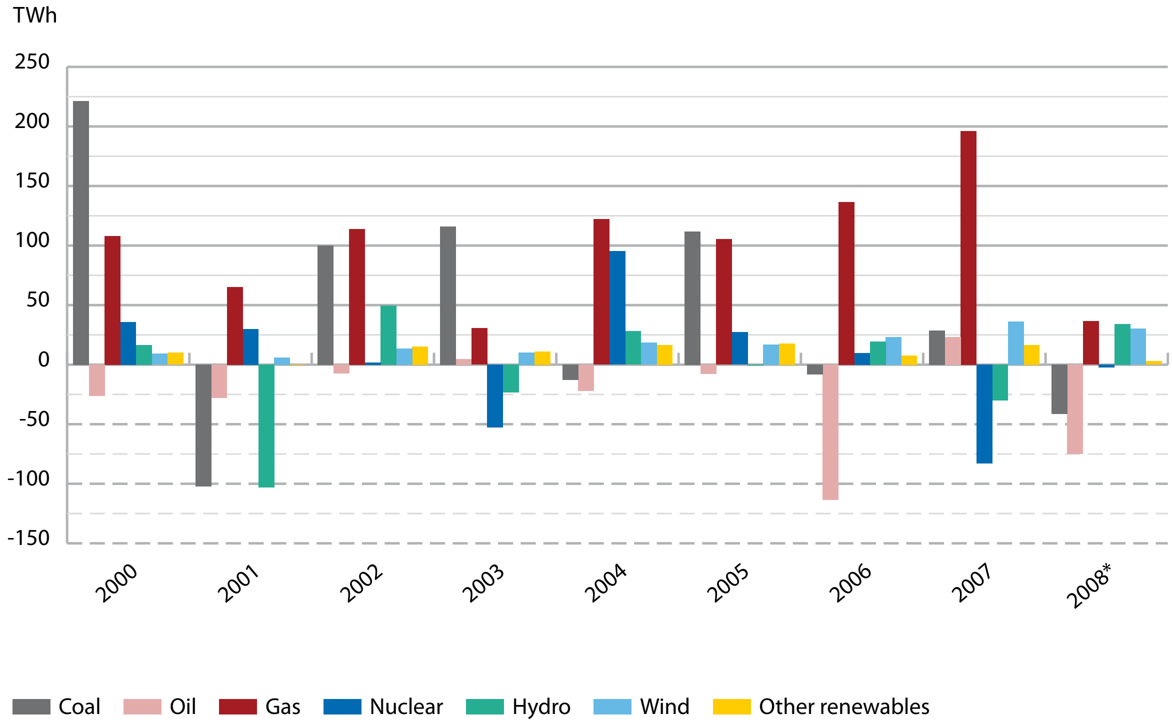
A key conclusion to be drawn from the sensitivity analysis is that the competitiveness of gas-fired generation is highly dependent on fuel prices. However, the combination of high fuel cost dependence and low investment cost dependence improves the actual market situation for CCGTs. Investment costs in a power generation plant can be considered "sunk costs" from the moment they are incurred. Once a plant is commissioned, the marginal cost of producing an additional unit of electricity should determine its operation (dispatch). Marginal costs roughly correspond to fuel costs; thus, CCGTs often have the highest marginal costs, even at relatively low gas prices. In many cases CCGTs are the marginal plants that determine the price in competitive markets. Hence, increases in gas prices are passed on as increases in wholesale electricity prices, creating a natural risk management mechanism or hedge. CCGTs tend to have most of their costs covered even if gas prices increase. While higher gas prices make alternative technologies more competitive, CCGTs may still be preferred because of their flexibility characteristics and the

12. Dixit, A. and Pindyck, R. (1994), "Investment Under Uncertainty", Princeton University Press.

13. Keppler, J.H. (1998), "Externalities, Fixed Costs and Information", *Kyklos* 42:547-563.

perception of lower risk involved. In other words, even if CCGTs are most vulnerable to being left out of the dispatch because they are often among the marginal units,[14] the absolute magnitude of the risk of capital loss is smaller for CCGTs due to the relatively low initial investment costs and their operating flexibility. This is one important factor in the emergence of gas-fired power as the option of choice in most OECD markets in recent years. Figure 6.25 shows incremental generation in OECD countries for the period between 2000 and 2008 according to the most recent IEA statistics.

Figure 6.25: Incremental power generation in the OECD area



*Estimate.
Source: IEA.

Over the past decade, OECD markets have thus seen a very marked increase in gas-fired generation, mainly CCGTs. The only other technology with noticeable capacity additions was wind power. CCGTs were the technology of choice due to the low price of gas, but also due to the low risk profile of this technology as well as its operational flexibility.

Fuel markets overview

Fossil fuel price expectations thus have an influence on the investment decisions in both fossil-fuelled and non-fossil-fuelled technologies. In the future, it can be expected that investment decisions in competing low-carbon baseload technologies, i.e. nuclear and CCS plants, will equally hinge on the expected level of fuel prices.

14. As CCGTs are often the marginal plant, they are the most financially vulnerable to being left out of the dispatch. Loss of gross margin can be total, whereas it is rare for coal or nuclear.

This section gives an overview of recent developments in the natural gas and coal markets, drawing on input provided by the gas and coal teams in the IEA Energy Diversification Division.[15] It also refers to the uranium market.[16]

Natural gas prices

Given the share of fuel cost in total LCOE of gas-fired CCGTs, and with CCGTs being the main option in many markets for new generation capacity, a key issue for investors is the absolute price level of natural gas. As already mentioned, gas price volatility is not necessarily a decisive issue for investors in CCGTs since they are typically setting the price of electricity and therefore can pass through fuel costs variations into wholesale electricity prices. But the absolute gas price level does matter for investors facing the choice between gas-fired and alternative generation technologies. Furthermore, due to the gas-electricity price link in most OECD wholesale electricity markets, gas prices influence revenues for all generation technologies.[17]

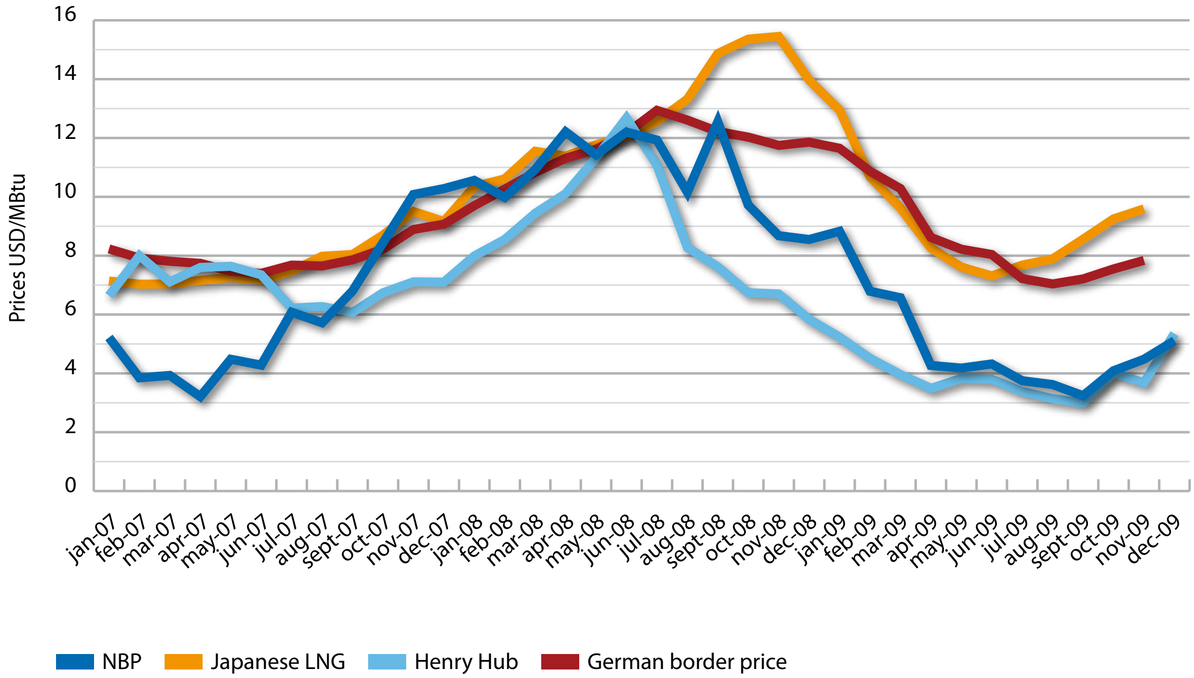
Gas prices have come down from their highs of 2008, when regional spot prices and oil-linked gas prices peaked at levels between USD 13 and 15 per MMBtu. Oil-linked gas prices in Japan and Continental Europe continued to increase throughout much of 2008 due to the time lag embedded in the contract formulas, but were declining in 2009 to reach USD 7 per MMBtu in the summer of 2009. However, spot prices started declining in mid-2008 reflecting the impact of the economic crisis on gas demand, but the decline was more substantial and immediate in the United States where Henry Hub (HH) registered a decrease from USD 13 per MMBtu in June 2008 to USD 6 in December 2008. National Balancing Point (NBP) spot prices in the United Kingdom have traditionally been influenced by continental oil-linked gas prices given that the United Kingdom imports gas from Europe during winter. Spot prices therefore declined at a slower rate reaching USD 9 per MMBtu by the end of 2008.

15. Brian Ricketts, IEA Coal Specialist, and Anne-Sophie Corbeau, IEA Natural Gas Expert, from the Energy Diversification Division, provided input on coal and gas prices respectively for this section.

16. Bob Vance, NEA Uranium Expert, NEA Nuclear Development Division, kindly reviewed the section on uranium markets.

17. As discussed in the boundary chapter on the functioning of electricity markets, the most fundamental change affecting the value of investments in liberalised markets is the inherent uncertainty about electricity prices in electricity markets. High capital cost and low fuel cost technologies will likely be competitive in the short run but they are under the constraint to cover their capital costs in the long run. For gas prices, higher fuel costs mean a smaller margin over which the plant can make profits. However, since capital costs are relatively low while fuel costs can often be passed through, this "profit volatility" has a smaller impact on the ability of the plant to cover total costs. Furthermore, high fuel cost technologies can respond by reducing output during hours in which the electricity has a price below its short-run marginal cost, where this is possible operationally.

Figure 6.26: Monthly gas prices in key OECD regional gas markets



The year 2009 saw two marked changes: US spot prices reached levels that had not been seen since 2002 – USD 2-3 per MMBtu – and, secondly, spot prices on both sides of the Atlantic were converging since February 2009. The sharp easing of the global supply and demand balance has indeed put strong downward pressure on spot prices. In both the United Kingdom and the United States, gas demand has declined. Meanwhile, US gas production continued to increase and plenty of LNG was available for the Atlantic basin as Japanese and Korean LNG imports declined in 2009, and a new liquefaction plant came on stream. As a result, HH and NBP spot prices have bottomed at levels less than half of oil-linked gas prices. Prices in the latter market are increasing again to reflect the strengthening of oil prices since February 2009.

Depending on the speed and geographical scope of economic recovery, spot gas prices may well remain weak for some years. Such spot prices account for more than half of OECD gas demand. As noted earlier, this affects the economics of CCGTs markedly.

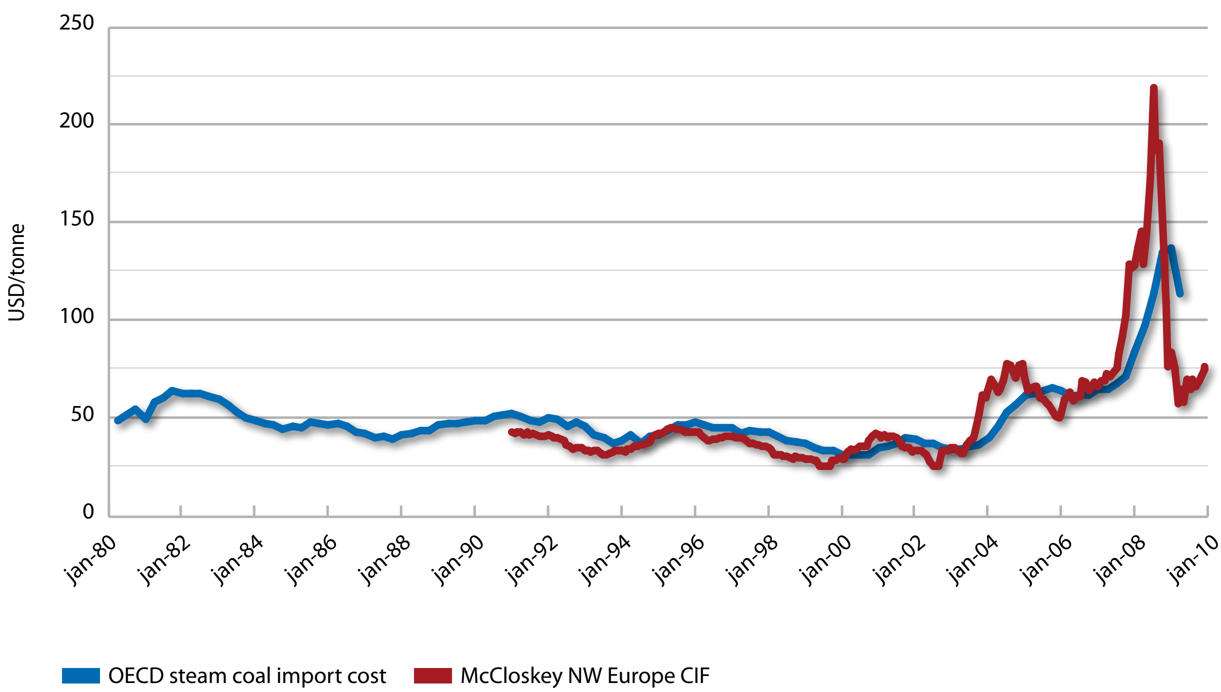
In this study, for the country levelised cost calculations a generic natural gas import price of USD 10.3/MMBtu was assumed for European imports and 12.7 for Asian LNG. Domestic natural gas prices were applied in producing regions, namely in North America (USD 7.78/MMBtu) and Australia (USD 8/MMBtu).

Further discussion on global gas markets can be found in the IEA annual *Natural Gas Market Review,* and a detailed longer-term view is presented in the *World Energy Outlook 2009*.

Coal prices

Figure 6.27 shows the average carriage-insurance-freight (CIF) cost of importing steam coal into OECD countries for each quarter since 1980. These costs, which exclude intra-EU trade, come from customs unit values and are therefore not for any particular coal quality, being simply a weighted average of all qualities. For comparison, a second data series is shown with monthly CIF spot prices for coal delivered to ARA (Antwerp-Rotterdam-Amsterdam) ports in Northwest Europe. In this instance, prices are based on a coal having a calorific value of 6 000 kcal/kg (25 121 kJ/kg) and <1% sulphur content. As might be expected, the chart shows spot prices leading customs values – most coal is sold under contract and changes in spot markets take time to filter through into prices paid by coal customers, even where contract prices are linked to spot market prices. Other "marker" prices (e.g. for Asian steam coal) could have been chosen to make this same point: the correlation provides confidence that reported OECD steam coal import costs reflect the dynamics of the international steam coal market.

Figure 6.27: Steam coal quarterly import costs and monthly spot prices



Since the 1980s through to 2003, there had been a general trend of falling real coal prices, notwithstanding the ups and downs associated with global economic cycles. Competition between coal suppliers drove through significant productivity improvements in the coal mining industry. Increased mechanisation led to greater output per man-year and reduced costs, particularly in those mines where longwall mining equipment could be deployed. Larger capacity equipment at open cut mines similarly improved productivity. Since 2003, the international coal market has been in a state of flux as rapid economic growth in China and other developing countries began to have a major impact on coal flows. Suppliers struggled to meet rising import demand: between 2003 and 2007, international coal trade grew by an average of 6.4% per year – a growth rate almost 50% above the long-term average between 1980 and 2002. Sharply rising demand in 2007 and early 2008 led to a sharp and unprecedented spike in traded coal prices. In response to this, investments in new export production capacity reached a historic high, although by 2009 the impact of the global financial crisis saw a number of investment projects delayed or cancelled. Given that world hard coal reserves (i.e. excluding brown coal) total 729 billion tonnes, with a shallow supply-cost curve, there is no reason to believe that the recent period of very high prices will last. The global recession has induced a considerable moderation in traded coal prices.

This study assumes a long-term OECD steam coal import cost of USD 90/tonne, noting that several OECD regions have costs well below this level and are not subject to the fluctuations of international markets. For these countries the study has used domestic coal prices for the country levelised cost calculations, in particular for Australia (USD 26.65/t of hard coal), Mexico (USD 87.50/t of hard coal) and the United States (USD 47.60/t of hard coal), noting that in some regions of the US, coal prices are significantly below this price.

Uranium prices

Most uranium is sold under confidential terms and conditions specified in long-term (multiannual) contracts. A number of long-term price indicators are produced that provide some indication of current prices. A more transparent spot market provides prices for uranium purchased for near-term delivery, but this represents only a small part of the market. The quantity of uranium traded on the spot market in a given year is usually equivalent to under 15% of the total quantity of uranium traded,[18] although in 2008 the volume of spot market transactions approached 25% of the total traded (this trend was continuing in 2009). The uranium market continues to rely on stockpiles of previously mined uranium (so-called secondary supplies) to meet demand, with freshly mined uranium typically supplying 55% to 60% of yearly demand. Since the early 1990s, one of the secondary sources of reactor-grade fuel has been augmented by uranium obtained from down-blending weapons grade uranium, which has had the effect of depressing prices and, in turn, investment in mine development.

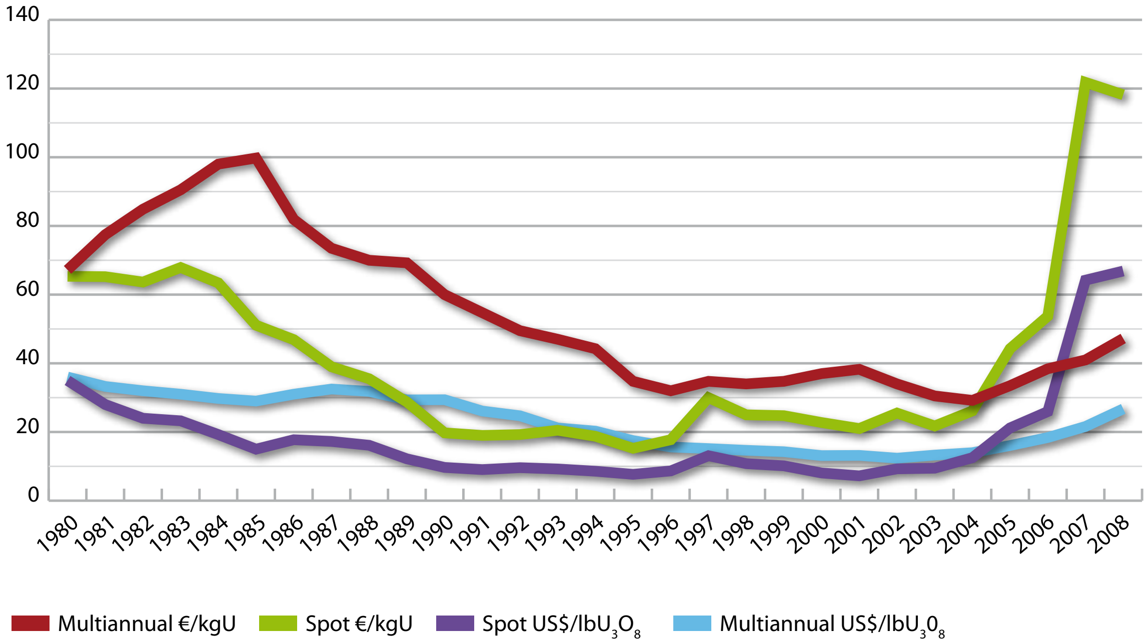
The current agreement under which Russian warheads are being dismantled and the uranium down blended to produce nuclear fuel ends in 2013. This, combined with renewed interest in constructing nuclear power plants to generate baseload electricity, has driven prices for uranium upwards, particularly since 2003. This has led to increased investment in uranium exploration, the identification of additional uranium resources of economic interest and increased investment in uranium mine development. These are timely developments, since secondary supplies are declining in availability at the same time that nuclear plants are being planned and built, increasing the need for freshly mined uranium.

According to the NEA/IAEA "Red Book",[19] uranium is mined in 20 countries, eight of which account for about 90% of world production (Australia, Canada, Kazakhstan, Namibia, Niger, the Russian Federation, the United States and Uzbekistan).

18. For example, in 2008 only 2.9% of all uranium deliveries to EU utilities were purchased under spot contracts. It should also be taken into account that the European market makes up around 30% of the global market.

19. NEA and IAEA (2008), *Uranium 2007: Resources, Production and Demand,* OECD, Paris.

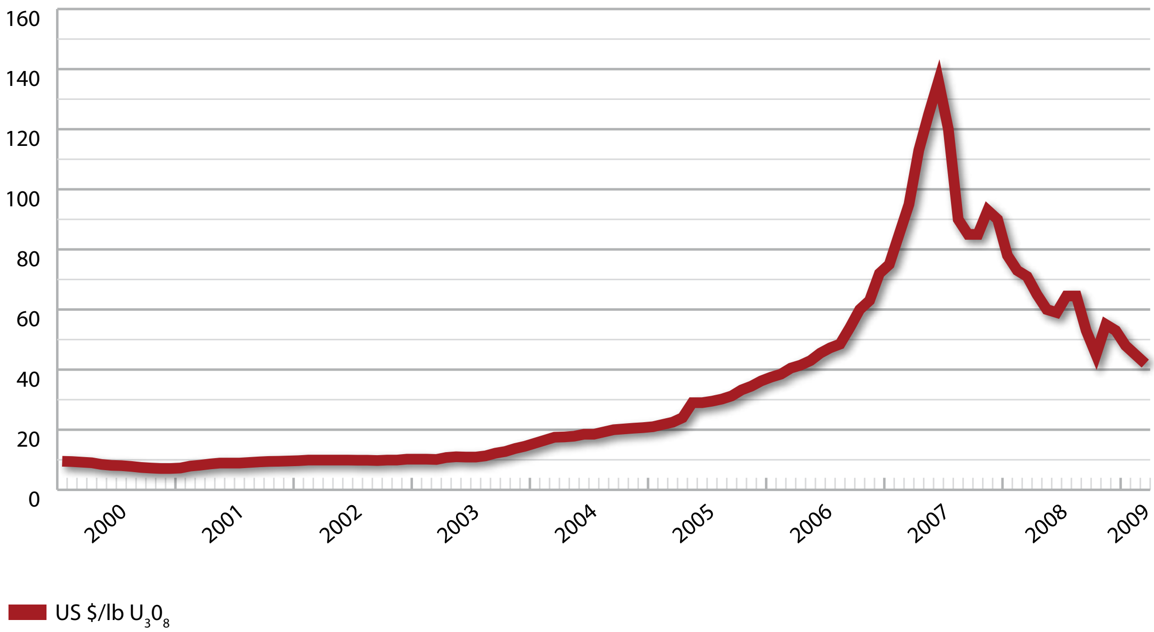
Figure 6.28: Average prices in the EU for natural uranium delivered under spot and multiannual contracts 1980-2008 (in EUR/kgU and USD/lb U_3O_8)



Source: Euratom Supply Agency 2008 Annual Report (http://ec.europa.eu/euratom/ar/last.pdf).

Information recently published by the Euratom Supply Agency on prices paid by utilities for uranium delivered to the European Union provides a good indication of global uranium spot and long-term (multiannual) prices, although it is important to note that the long-term prices shown here reflect contracts that in some cases were signed several years ago when prices were much lower. As is the case for other commodities, the spot market price for uranium was driven rapidly upwards in 2006 and 2007, at least in part by speculators seeking to profit from the price movement (see Figure 6.28 and Figure 6.29). Resistance by utilities to purchase uranium at such high prices, combined with the worldwide financial crisis, has since exerted downward pressure on uranium prices. In addition, hedge funds and investors who had been very active purchasers since 2004 were forced to sell to meet cash requirements, putting additional downward pressure on spot prices.

Figure 6.29: Monthly natural uranium spot prices in USD/lb U_3O_8



Source: The Ux Consulting Company, LLC – Euratom Supply Agency 2008 Annual Report.

Uranium spot prices which peaked at close to 140 USD/lb U_3O_8 in mid-2007 (compared to around 20 USD/lb in 2004) had decreased to about 50 USD/lb U_3O_8 by December 2008. Long-term price indicators had declined from about 95 USD/lb U_3O_8 in mid-2007 to about 70 USD/lb U_3O_8 in December 2008.

As noted in Chapter 3, the cost of U_3O_8 (uranium ore or yellowcake) only constitutes about 5% of the total costs of generating electricity from nuclear power so increasing uranium prices have only a small direct impact on the cost of electricity generated from nuclear power.

An established and effective market for the different front-end services exists. According to the IAEA, 13 commercial-scale uranium enrichment facilities are currently in operation worldwide [20] and 40 commercial-scale fuel fabrication facilities are in operation.[21] Most of the activities are performed under long-term contracts. Spot-market activities play a far more limited role.

20. Located in China, France, Germany, Japan, the Netherlands, Pakistan, the Russian Federation, the United Kingdom and the United States.

21. In Argentina, Belgium, Brazil, Canada, China, France, Germany, India, Japan, Kazakhstan, Korea, Pakistan, Romania, the Russian Federation, Spain, Sweden, the United Kingdom and the United States.

6.3.3 Carbon costs

Most OECD countries have various subsidy schemes that function as compensation for non-emitting technologies, especially for renewable energy. CO_2 prices or costs are explicit in the European Union (EU) with the introduction of the European Union Emission Trading Scheme (EU ETS) in 2005. There are also indications of investors in other OECD countries, for example in the US, taking carbon pricing into account when making investment decisions, on the expectation that such a price will emerge in the future.

CO_2 prices in the EU ETS have fluctuated between USD 10 and 40/tCO_2,[22] reflecting great uncertainty, particularly regulatory uncertainty and initial problems related to the start of the system, but also reflecting competition between gas and coal, depending on their relative prices. This study assumes a reference cost of USD 30/tCO_2 for all OECD countries.

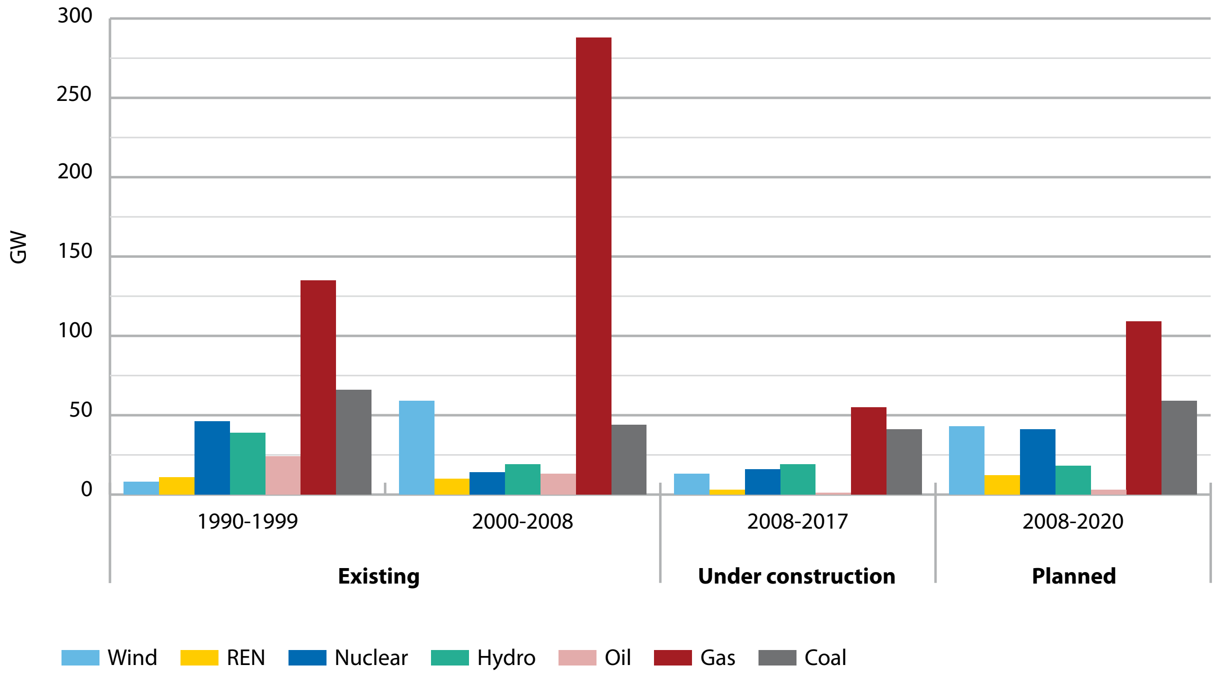
Uncertainty about climate policy is one of the greatest risk factors that investors in power generation are faced with at the moment. Climate policy may have a significant impact on costs of generating electricity with different options. This is an intended effect since the main thrust of climate policy is to alter the way power plants are operated and the technology choices are made. In particular, if ambitious carbon reductions are to be achieved globally, the power sector may need to be rapidly decarbonised in many regions. Uncertainty about future climate policy thereby creates considerable uncertainty about generating costs of the different options. The analysis of investment decisions in power generation under climate policy uncertainty is more fully discussed in Chapter 9 on "Levelised costs and the working of actual power markets".

A tax on CO_2 emissions and a price resulting from a quantitative cap on emissions may under certain conditions such as the free allocation of allowances have different impacts on investors. A tax can be taken directly into account by investors who can make their operational and investment choices accordingly. If the tax is formed by a robust calculation of the external costs of emitting CO_2, the tax will result in an optimal internalisation of these costs. There will, on the other hand, be uncertainty about the CO_2 reduction volumes achieved. If policy makers have a quantitative target of acceptable CO_2 emissions in the atmosphere, such as the 450-ppm target, a cap and trade system will lead to uncertainty about the price of CO_2 abatement. Investors will have to analyse the fundamental factors determining the price of CO_2 emissions in the future in order to formulate CO_2 price expectations for decision making. Investors are in a good position to analyse and understand market fundamentals if the market place is transparent and competitive. The only uncertainty which is difficult to manage is the political uncertainty about the actual reduction requirement. The sooner policy makers can make decisions on climate change mitigation policies, and the more regulatory certainty they provide, the less risky investments in new power generation will be for investors. This insight is emphasized by an IEA study that analyses the implications of climate policy uncertainty on investment behaviour in the power sector. Climate policy uncertainty is found to weaken and delay investment incentives for low-carbon technologies. A stable carbon regime for at least 10-15 years is necessary for inducing cleaner investment in the power sector. Certainly, policy uncertainty weakens and delays investment in all technologies, as people may prefer to wait until obtaining more clarity before committing investment in a particular technology. Further, decision makers would like policy decisions of all kinds to be stable, not just carbon policy decisions. Reducing risks also means reducing costs.

22. In reality, between EUR 0.03 and 34.35, although prices only fell below USD 10 at the end of the transition period.

So far, carbon pricing has failed to make an impact on investment decisions in the power sector. In practice, in the OECD area, CCGTs have dominated the scene of new power generation since the early 1990s. The only other significant source of increase in installed capacity during the last decade, in addition to CCGTS, is in wind power, notably in Europe. New coal-fired generation projects in OECD countries meet considerable resistance for environmental reasons, and their economic feasibility is highly dependent on environmental policies. Plans to increase coal-fired capacity tend to not reach the stage of construction, or when they do, they do not lead to a net increase in coal-fired capacity. Such a pattern is typical of many OECD countries, where near-term new capacity is gas-fired (under construction), while planned capacity expansions are coal-based. Finally, the so-called nuclear renaissance has not yet materialised in the OECD area, outside Asia. Figure 6.30 shows power generation capacity expansions in OECD countries.

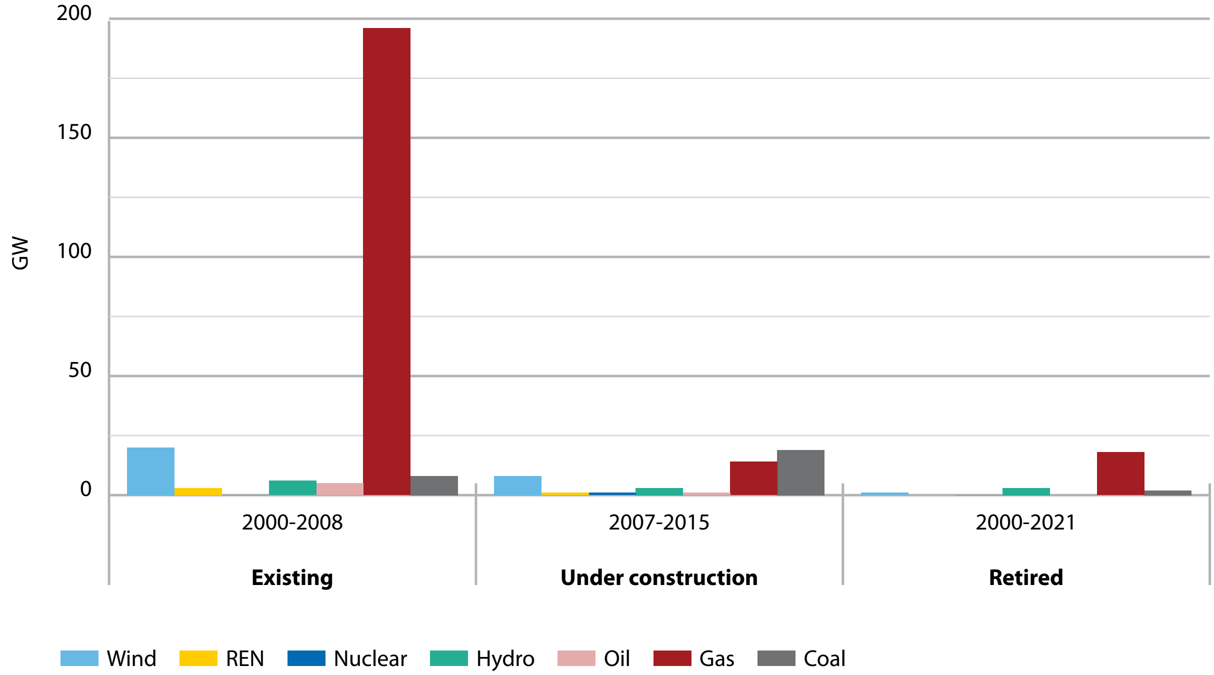
Figure 6.30: Changes in installed capacity in the OECD area (GW)



Source: Platts, 2008.

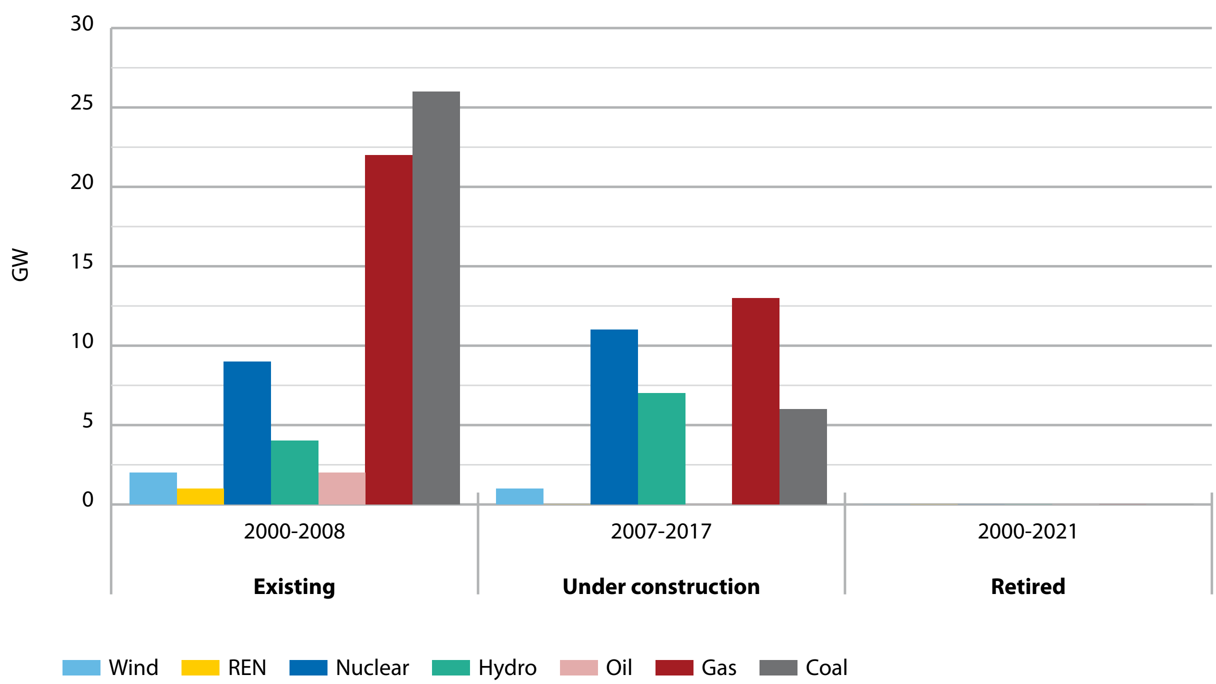
In the 1980s and 1990s the dominant trend was first of all to move away from oil-fired generation. In the 1980s the prevailing alternative was nuclear power. In the 1990s it was gas, with coal also playing an important role throughout these years. Since 2000, trends have changed with a very marked inflow of gas-fired generation, mainly CCGTs. Three-quarters of the new gas-fired plants in the OECD area were added just in the United States.

Figure 6.31: Changes in installed capacity in the OECD North America region (GW)



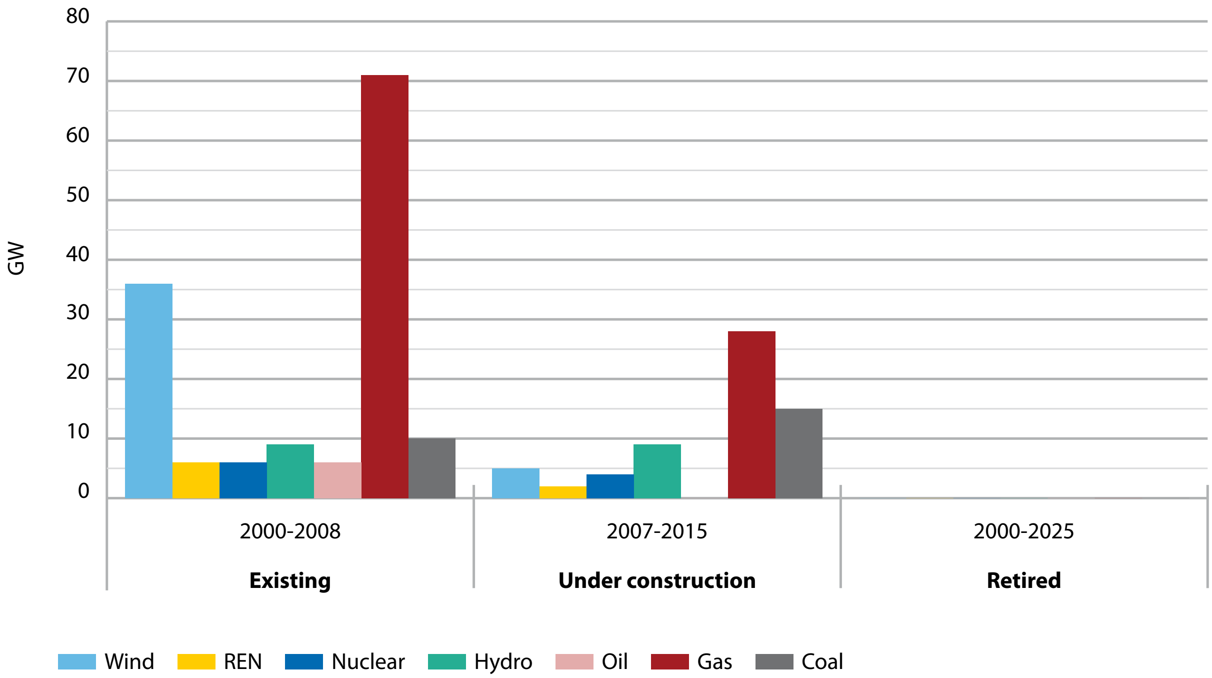
The bulk of coal and nuclear capacity expansion has taken place in the OECD Asia-Pacific region (Figure 6.32).

Figure 6.32: Changes in installed capacity in the OECD Asia-Pacific region (GW)



Finally, particularly in OECD Europe, stricter environmental standards, including a carbon price, coupled with higher fossil fuel prices, have contributed to the reduction of the relative cost of renewable technologies. Renewable sources are increasing strongly in most OECD countries and many non-OECD countries. But this strong development is usually underpinned by direct support such as feed-in tariffs, premiums and purchase obligations rather than by the penalty imposed by internalising the costs of CO_2 emissions. Where applicable, this has not for the moment been the most significant driver for new investment in renewable power sources. (Note that the short lead times for renewables, especially wind, tend to mean that the likely future contribution of these technologies, as shown in the under construction section of these graphs, is understated.)

Figure 6.33: Changes in installed capacity in the OECD Europe region (GW)



Experiences from the first phases of the EU ETS give some indication of how the implementation of a cap and trade system affects investments. In the first phase, the CO_2 reductions required by the power sector to fulfil government commitments were mainly delivered through switching from coal to gas within existing installations. While fuel switching within the electricity sector was the dominant form of emission reduction brought about by the EU ETS, other forms of abatement have also appeared during the trial period, e.g. improvements in energy efficiency in existing power plants. Wind power also expanded considerably. At the same time, significant plans for expansion of coal plants emerged, as a response to higher gas prices. Based on this experience the EU ETS was claimed to mainly have changed the pattern of operating existing plants.

Several reasons for this relatively marginal effect were highlighted. First, making commitments on CO_2 reductions only to 2012 was considered too short for investors considering cleaner alternatives (moreover, Phase I only lasted three years: 2005-2007). The free allocation of emission credits in the first phases ("grandfathering") also showed generators that it was possible to influence national allocation plans to their advantage. Nonetheless, the clear policy indication regarding the extension and strengthening of the EU ETS and the price signal provided investors with more certainty in the later years of the trial phase and the first years of the second phase. In addition, experiences of the EU ETS also showed that allocation rules and a CO_2 price are not the only factors affecting decisions concerning investment and operations.[23] Economic factors such as capital costs and expected fuel prices are important, and strategic considerations related to portfolio optimisation, local siting and licensing requirements, and support mechanisms favouring some technologies also matter substantially. Moreover, the first trading period of the EU ETS has seen large variations in power plant capital costs and fossil fuel prices, as well as electricity prices. Changes in investment plans coinciding with the start of the EU ETS may thus reflect factors other than CO_2 prices or the effects of allocation provisions.

With the EU agreement to proceed with the EU ETS beyond 2012 based on full auctioning of emission rights for the power sector, and in a more harmonised setting, a considerably clearer signal is sent to investors. Some early indications of these changed signals are even being seen before the agreement has materialised in fully agreed detailed legislation. Several of the planned coal plants have been cancelled, and other state-of-the-art coal plants are proceeding. Investors are showing great interest in investing in nuclear power in those countries where this is feasible, extending lifetimes or avoiding early closure of nuclear plants, and also pushing for opening the debate about nuclear power in several of the countries where this has been ruled out so far.

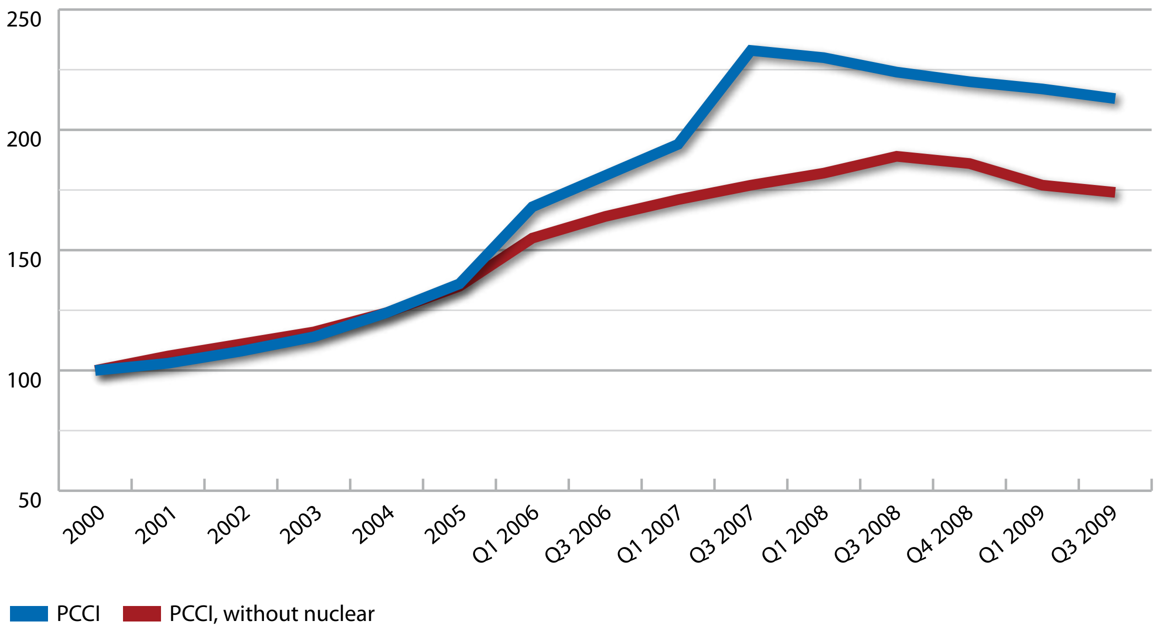
With a confirmation of the continued use of the EU ETS and with firm targets for CO_2 abatement, investors have an improved ability to analyse supply and demand for power, factoring in CO_2 restrictions. The greatest political uncertainties that remain for investors in the EU are related to the other climate change abatement instruments that the EU has decided to use. An energy efficiency target of 20% reduction in energy consumption below a base case by 2020 was decided together with the 20% CO_2 reduction target by 2020. The success of these efforts will greatly affect the need for, and type of, new power generation. For example, if efficiency policies are more successful in reducing baseload rather than peak demand, then more peaking plant may be needed. The EU also agreed on a binding 20% renewable target by 2020. This can have an even greater effect on the need for non-renewable investments. There is uncertainty about what share of the renewable target will be met by the power sector and other sectors, and there is some uncertainty regarding the full achievability of the renewable target. Nonetheless, the share of non-hydro renewable power generation would have to rise sharply for this goal to be met. Since the renewable target is intended to be met through special incentives, at least in the initial phase, the increase in non-CO_2-emitting renewable electricity will make the CO_2 constraints less binding and will hence have a tendency to push down the price of CO_2 emission permits. Analysing the fundamentals in a market place with considerable politically driven uncertainty about demand and renewables will add to risks for investors.

6.3.4 Construction costs and lead times

Uncertainties over changing material and engineering costs, availability of skilled labour, as well as power market supply and demand dynamics, complicate the task of forecasting the evolution of power plant construction costs. A cursory look at recent trends delineates a marked power plant cost increase since the middle of the decade, owing to the escalation in the prices of hydrocarbons, commodities and bulk materials. Although the higher prices of raw materials led to roughly similar generation cost escalation for all generating technologies, the competitive margin of capital-intensive technologies, in particular nuclear and wind, has been particularly affected. This inflationary trajectory was reversed after reaching a peak in August 2008, as can be seen in Figure 6.34 which traces the monthly movement of the IHS CERA Power Capital Cost Index (PCCI), a composite index based on the weighted sum of construction costs for nuclear, gas, coal and wind power plants indexed to the year 2000.

23. See Ellerman *et al.* (2010), *Pricing Carbon: The European Union Emissions Trading Scheme,* Cambridge University Press, United Kingdom.

Figure 6.34: IHS CERA Power Capital Cost Index (PCCI)



Source: IHS CERA Power Capital Costs Index (PCCI), July 2009.

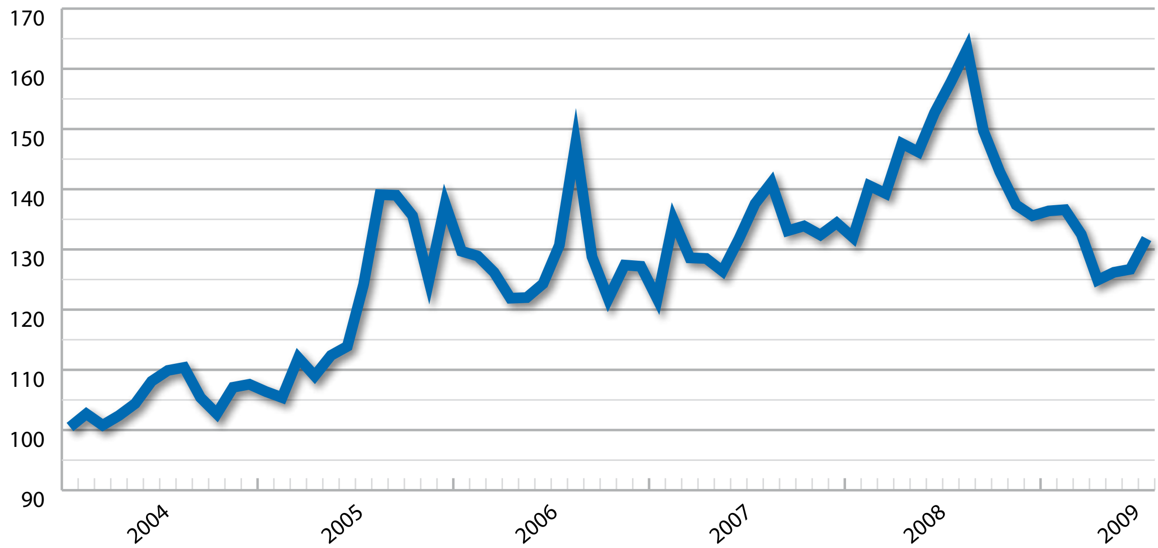
According to the IHS CERA Power Capital Cost Index (PCCI), which tracks the costs of coal, gas, nuclear and wind power plants in North America, the construction costs for power plants have grown by 217% between 2000 and the beginning of 2009 (IHS CERA, 2009). The cost increases are not uniform for all plant types, but especially affect the capital-intensive ones such as coal, nuclear and wind. Whether power plant costs will remain that high is an open question. In the first quarter of 2009, IHS CERA cites a drop of 6% in the investment costs of coal power plants, mainly related to reduced labour costs and declining ancillary equipment costs.

Since the first quarter of 2008, the fall in construction costs was largely limited to nuclear power plants, but in the final quarter of 2008 and into 2009, the downward trend has spread to non-nuclear plants as well, driven primarily by lower prices for steel, copper and hydrocarbons. The decline has been amplified by the easing power supply and demand balance, as industrial power demand fell in line with the economic downturn.

Apart from the power market fundamentals, a large potential for continued construction cost reduction arises from using standardised plant designs, constructing identical plants in series, multi-unit sites and reducing the construction period. These measures provide cost savings mainly through the avoidance of much first-of-a-kind (FOAK) effort and the efficiency gains which provide opportunities for reducing the average capital cost per unit of installed capacity.

While the trend of decreasing material costs is likely to continue in the short term, in the medium to long term, an economic recovery can be expected to stimulate electricity demand and new power project orders, thereby exercising renewed upward pressures on power plant construction costs. The Electric Power Generation Producer Price Index (PPI) reported by the US Bureau of Labour Statistics already suggests a slight upturn in demand with the corresponding increase in electric power generation producer prices following a trough reached in April 2009 (see Figure 6.35).

Figure 6.35: Electric Power Generation Producer Price Index



Source: US Bureau of Labour Statistics.

In addition to the multiplicity of factors influencing the evolution of construction costs, cost forecasting for new projects is further complicated by the diversity of industry practices with the ensuing cost difference between lump-sum, turn-key (fixed price) projects and other engineering, procurement and construction (EPC) contracts characterised by more flexible risk allocation arrangements. Therefore, it is not surprising that for all electricity generating technologies examined in the study, the reported data indicate a large variation of construction cost projections, owing to country-specific differences in key cost drivers.

Power generation investments are not only highly capital intensive, but also have long lead times, which increases the risk of construction cost overruns. Caused by various factors ranging from poor project management to grassroots opposition to a particular site resulting in project delays or even cancellations, construction delays expose power projects to the risk of a variety of additional costs that, in most cases, are beyond the control of the project management team. Such risks include: increased total interest during construction (IDC), as interest expenses will need to be capitalised over a longer period of time; potential price escalation for equipment, material and labour; obsolescence of technologies; or additional regulatory requirements. On the other hand, a shorter construction period reduces IDC and results in an earlier start of cash inflows from plant operation, thereby improving the project profitability.

It has to be noted that the present study calculates levelised costs of electricity based on the assumption of a uniform distribution of construction costs over technology-specific construction periods of seven years for nuclear, four years for coal, two years for gas, and one year for wind and solar plants. A separate analysis has been performed to test the impact of different cost allocation schedules on LCOE based on the example of nuclear generation, which presents the most interesting case study due to its longer lead time. The Median case assumption of a uniform cost allocation has been compared with a "mid-peak" schedule (with the peak of 50% of construction costs expensed in the middle of the construction period), an "anticipated" schedule (with the 50% peak falling in the first year) and a "deferred" schedule (with a peak cost allocation postponed until the last year).

When the interest applied during construction to the overnight cost is compounded at a 5% discount rate, the impact of different construction schedules is very limited (with a corresponding variation of LCOE in the range of 0.1-4%). At a 10% discount rate, on the other hand, the LCOE tends to be more sensitive to different construction cost allocation schedules. While the difference between "uniform" and "mid-peak" cost schedules remains insignificant, a front-loaded "anticipated" schedule increases the LCOE by 12% and a back-loaded "deferred" schedule decreases the LCOE by 11%. Therefore, in a high discount rate market environment, finding an appropriate construction cost schedule has the potential to offer opportunities for important cost reductions for capital-intensive technologies with long lead times such as nuclear power.

6.3.5 Load factors and lifetimes

The load factor of a power plant indicates the ratio of the electrical energy produced by a plant and the theoretical maximum that could be produced at non-interrupted power generation. Thus an average lifetime load factor would equal the average of the total output of a plant over its lifetime divided by the maximum possible output of that plant. For nuclear and fossil-fuelled power plants, the load factor is determined by planned unavailability relating to maintenance or refuelling downtime, unplanned outage due to equipment failure and shutdowns when the station's electricity is not dispatched. Assuming baseload generation, the study applies a generic 85% load factor in calculating levelised average lifetime costs for nuclear, coal-fired and gas-fired power plants in order to be able to compare the relative cost of a kWh produced by these different technologies. Since for renewable sources, such as wind and solar energy, power output is influenced not only by the above-mentioned factors but also by site-specific availability of wind and solar irradiation, the cost calculations were based on country-specific load factors reported in the questionnaire.

The load factor defines the amount of electricity produced per unit of generating capacity that will earn revenues to cover both the capital and the operating costs of a power plant. On the one hand, increasing the load factor offers an opportunity to recover the fixed capital costs of power plants more quickly by increasing output. On the other hand, fuel and variable operation and maintenance (O&M) costs also change along with the load factor variation.

It has to be noted that *lifetime* load factors and average *annual* load factors can and do differ in practice. Similarly, it has to be taken into account that despite considering gas as a baseload technology for the purposes of this study, in practice gas-fired generation tends to be run as mid-merit and peak load, and thus presents significantly lower load factors that those of nuclear and coal-fired plants. Furthermore, in systems with a high penetration of variable renewables, where gas is often the back-up generation for these, load factors are even lower. According to the results of the sensitivity analysis, see above, this increases the costs of gas-fired power, but to a lesser extent than other technologies. Due to a combination of technical and economic factors, gas is the most likely back-up technology where hydro power is unavailable or fully exploited. A brief discussion of annual and lifetime load factors for different technologies is included in Chapter 3.

In the electricity industry, the operational lifetime of assets is typically long, often over 50 years. Owners count on this period to recover their investment and to obtain an adequate return. Based on the technical characteristics of *new* plants, lifetimes for different technologies have been assumed to be 60 years for nuclear, 40 for coal and geothermal plants, 30 for gas, 25 for wind and solar, and 20 for wave and tidal.

As noted earlier, a key issue in this regard is the impact of an early retirement of a plant if, for example, more stringent environmental laws are adopted in the context of climate change negotiations. If operational costs increase further than expected as a result of increasing fuel costs or emissions charges, older, less efficient thermal plants become uncompetitive and have to be mothballed or decommissioned sooner.[24]

24. WEO 2009 shows that in a carbon-constrained world (the 450-ppm Scenario), an additional 585 GW of coal plants are mothballed or retired earlier, mainly due to raising CO_2 prices, over and above the 450 GW retired in the Reference Scenario. This equates to almost three-quarters of the entire installed coal plant capacity today.

System integration aspects of variable renewable power generation

7.1 Introduction

This chapter addresses the impacts on power systems of integrating electricity from variable renewable energy sources such as wind power. Variable renewable energy technologies exploit natural resources which are not constant and thus not fully predictable. Such technologies shall henceforth be referred to as varRE. VarRE technologies also include solar photovoltaic, solar thermal electricity generation (also known as concentrating solar power or CSP), tidal energy, wave energy and run-of-river hydro. Although for reasons of conciseness the latter will not be addressed here, many of the aspects discussed will apply to a greater or lesser extent.

Not all renewables are variable. Geothermal, biomass and reservoir-based hydro are dispatchable renewable energy forms. Solar thermal electricity generation (STEG) will increasingly include integrated thermal storage to bridge the night-time gap in output, and significantly reduce the variability factor, although increasing investment and hence generating costs.

This chapter focuses on the balancing of high shares of wind energy on a timescale that can range from seconds to days. At the end of the chapter, a brief discussion is included of the contribution of wind power to the *adequacy* of a power system – its ability to meet demand during peaks. VarRE contribution to the *security* of a power system – its ability to withstand sudden and unanticipated disturbances – is not addressed here. Most modern wind turbines are equipped with a range of control characteristics which enable them to support the stability of the power system in normal and system fault conditions, relating in the main to power and voltage control and the ability to “ride through” faults.

7.2 Variability

Variability is not new in power systems. Demand fluctuates continually, as does supply albeit to a lesser extent. However, a greater share of varRE will increase the aggregate variability and uncertainty seen by a power system. As penetration grows and results in variability of similar amplitude to demand, measures will need to be taken to ensure continued reliable operation.

VarRE output fluctuates upwards and downwards according to the resource: the wind, cloud cover, rain, waves, tide, etc. Particularly when aggregated over large areas, output does not drop from full power to zero, or *vice versa,* but rather increases and decreases on a gradient as weather systems shift. It is measured in terms of its “ramp” rate – the increase or decrease in output per unit of time. Ramp rates may on occasion be steep: wind plants for example are designed to cut out in storm conditions when a certain wind speed is reached.

Modest shares of varRE have been shown to have little or no impact on power system operation. However, large shares present new challenges. Table 7.1 lists the national penetrations of wind energy in power systems at the end of 2008.

Table 7.1: Penetration of wind energy in electricity production

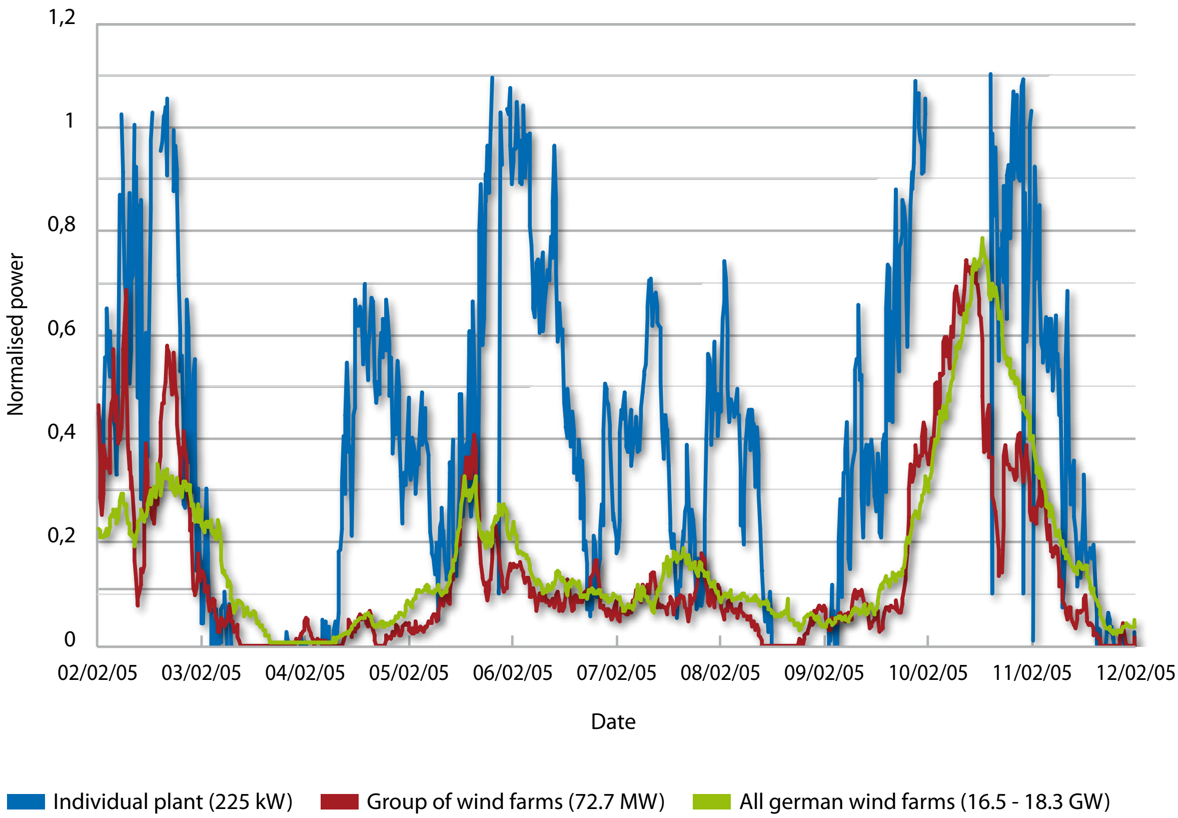
Country	TWh wind in 2008	Percentage of total electricity production 2008
Denmark	7	19.3
France	6	1.0
Germany	40	6.5
Italy	6	2.0
Portugal	6	11.3
Spain	32	11.7
United Kingdom	7	1.3
United States	52	1.9

7.2.1 Smoothing variability

The outputs of individual turbines in a wind plant do not completely correlate. Similarly, the output correlation of separate wind plants tends to decrease with distance, particularly on land. This phenomenon, if the output of all wind plants in a certain area is considered simultaneously, results in a “smoothing” effect, to some extent reducing the peaks and troughs in output. It also means that the sudden loss of all wind power over an entire power system at the same instant – due to a drop in the resource – is not a credible event. In effect, while a single turbine may have no output for more than 1 000 hours in a year, the output of many plants is always above zero. The way in which varRE plants are distributed or concentrated among or in regions is also an important factor. For instance, if all the wind capacity is concentrated in one area, then the smoothing effect will be limited.

Figure 7.1 illustrates the smoothing effect of geographic spreading “geo-spread” on the output of wind power plants in Germany. The figure shows a ten day period of normalised power production from a) a single turbine, b) a group of wind power plants, and c) all wind power plants in Germany. While the output of a single turbine fluctuates very rapidly between maximum and zero output, aggregated German production shows a much steadier output profile, ramping up and down more slowly.

Figure 7.1: Smoothing effect of geo-spread on wind power output in Germany
(2-12 February 2005)

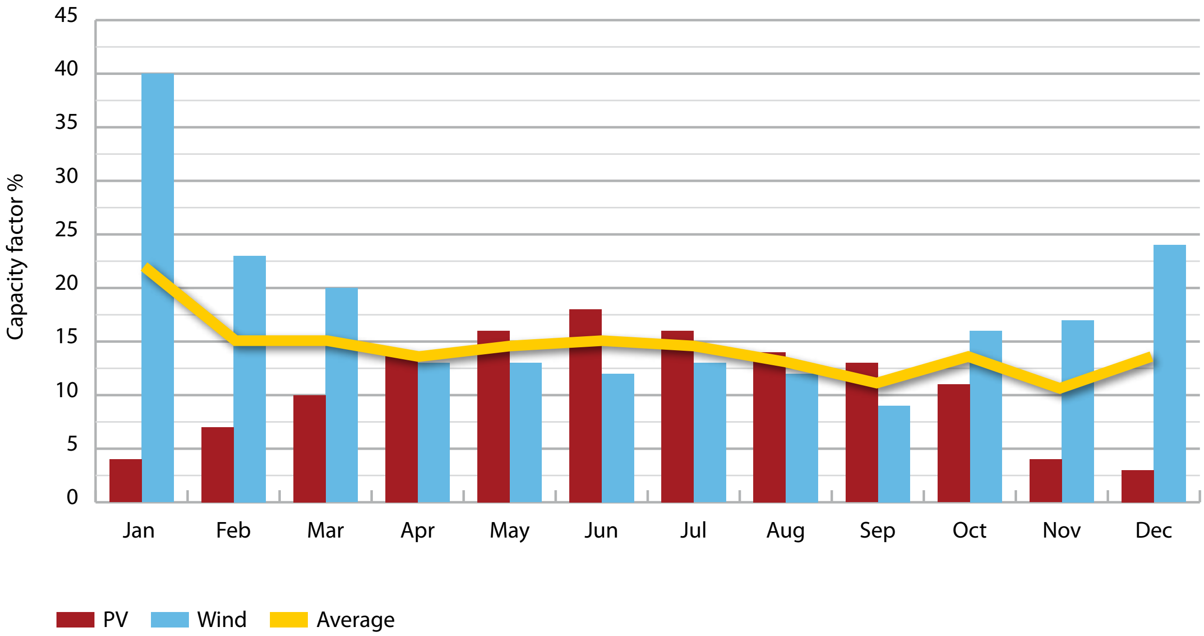


Source: ISET (2006).

The scale of balancing areas, and the way in which wind power plants are dispersed over them is thus of great importance. Landscape effects are also crucial. Initial experiences from offshore wind farms suggest that wind speed profiles are more uniform than onshore, *i.e.*, that a given distance between onshore wind farms is likely to offer greater "smoothing" of their aggregated output than the same distance between offshore plants.

Similarly to geo-spread, the output of different variable technologies may also show negative correlation. Figure 7.2 illustrates this "techno-spread" in the case of wind and solar PV in Germany. Seasonal capacity factors are seen to be complementary, with high wind in winter and more sun in summer. For techno-spread to achieve a significant smoothing, the outputs of such technology types must, however, be of comparable scale. The effect of techno-spread is not only observed on the seasonal timescale: in the United Kingdom, for example, wave and wind power time series have been found to have a low correlation on a daily basis.

Figure 7.2: Monthly capacity factors for wind and PV, Germany, 2005



A crucial caveat must be borne in mind when considering these smoothing effects, which is that the aggregated output of varRE plants must be part of a single balancing area. It is assumed that adequate, uncongested transmission capacity exists to allow unhindered flow of electricity. Should congestion occur to the extent that one part of the system is isolated from the rest, then the varRE ramp rates in both isolated parts are likely to be more pronounced.

7.2.2 Predicting variability

Geo-spread smoothing is particularly effective over intra-hour periods. Over longer periods, even greatly dispersed wind portfolios will show large fluctuations in output (Figure 7.1). Accurate prediction of wind power output is crucial to reduce the allocation of reserves in advance, particularly on a timescale of several hours to days ahead of dispatch.

Experiences with forecasting show that the overall shape of day-ahead electricity production can be predicted most of the time. However, the level of accuracy is not as high as load forecasts. Accuracy improves when combining predictions over larger areas, and closer to real-time, although significant inaccuracies are still seen in amplitude and timing of output.

Increased accuracy and reduced uncertainty are important to encourage the use of forecasting in power system operation. Greater reliability of forecasts will facilitate advance scheduling of less flexible plants, thus reducing wear and tear in the more flexible plants. The intervals at which forecasts of wind and load are updated can have important effects. The possibility of intra-day re-dispatch based on an updated forecast, for instance, will reduce costs relative to systems where dispatch of all plants is fixed on the previous day, which can in practice mean up to 36 hours ahead, and even more in extreme cases.

7.3 Flexibility

In addition to the smoothing effects of geo-spread and techno-spread and once forecasting has been refined and introduced in system operation, power systems will still require some enhancement of flexibility to absorb large shares of fluctuating varRE output in a reliable manner. A flexible system can both rapidly supplement periods of low varRE output from other sources on demand, and dispose of large surpluses when demand is low. Although the term "flexibility" is traditionally associated only with quickly dispatchable generators, such as open cycle gas and reservoir hydro, a wider definition also encompasses how the system transports, stores, trades and consumes electricity. In other words, flexibility expresses the full capability of a power system to maintain reliable supply in the face of rapid and large imbalances.

Before considering the needs of new varRE plant, the system's existing flexibility needs must be taken into account. These consist mainly of balancing fluctuating demand, demand forecast errors, sudden outages of power plants or transmission lines (contingencies), and any existing varRE in the system. What is left over can to some extent be considered to be available for balancing additional variability in the system. It is important to note that using more reserves for balancing purposes may have important impacts. These include the likelihood that the system will be operated closer to its technical limits as well as the wear and tear on plants caused by ramping production up and down to a greater extent that originally intended.

At present no standard method exists for the assessment of available flexibility for use in balancing varRE output, nor for assessing varRE requirement for flexibility. This is partly because power systems worldwide vary enormously – in terms of scale, interconnection, generation, storage, transmission and distribution, demand behaviour, and market rules. Consequently there exists no single, "one-size-fits-all" solution to facilitate the integration of large shares of varRE.

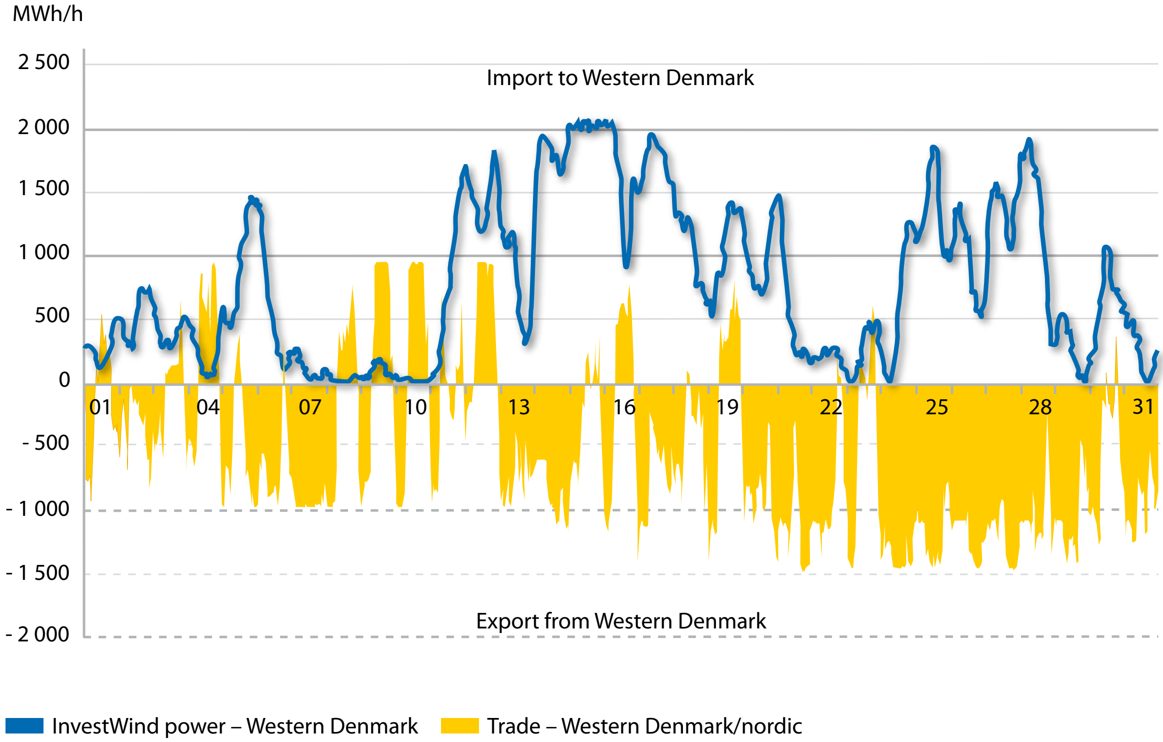
7.3.1 Optimising the use of existing assets

Recent IEA analysis suggests that when more flexibility is required to balance varRE output, a number of operational measures should be considered, before decisions to invest in new capacity are taken. Although operational measures will carry some cost, in essence they can be seen as efficiency measures: optimising the use of existing flexibility in the power system and enabling a higher varRE penetration with minimum impact on system reliability. They include:

- *Larger balancing areas* – to enable a geographically larger area to rely on a smaller proportion of reserves to maintain system reliability, and enable imbalances to "flow" to where they cost least to cover (as well as increasing smoothing effects).
- *Demand shaping through demand side management and response* – moving a measure of demand from peak to off-peak periods.
- *Improved output forecasting and intra-hour re-dispatch* – to allow more efficient scheduling of flexible reserves.
- *Increased control of transmission and distribution assets* – to increase transmission capacity and reduce congestion during key periods and over critical line lengths.

A well-known example of operational increase of flexibility is found in the Nordic power market, which includes Denmark, Finland, Norway and Sweden. In this market, day-ahead, intra-day and intra-hour trade is coordinated among the countries to optimise the use of physical resources. This means that if the cheapest way to balance a system net imbalance caused by a wind change in Denmark (via the intra-hour regulating market) is to change power production in Finland (at a distance of around 1 400 km), then this bid is accepted, assuming that there is sufficient transmission capacity available. The Nordic market has facilitated very strong wind energy development in the region, as Danish wind energy can rely on Norwegian and Swedish hydropower for balancing. Figure 7.3 illustrates the value of this international trade during December of 2003, when cross border flows were very high between Western Denmark, on the one hand, and Norway and Sweden, on the other.

Figure 7.3: Western Denmark's electricity trading with Norway and Sweden: wind power for hydropower



When the opportunity for optimising the use of existing flexibility is exhausted, additional, *capacity* measures must be taken. Such measures may include additional flexible power plant capacity, storage capacity (including pumped hydro and new storage concepts such as electric cars), reinforcement and expansion of transmission and distribution networks as well as better interconnection among adjacent areas.

7.4 Costing variable renewable integration

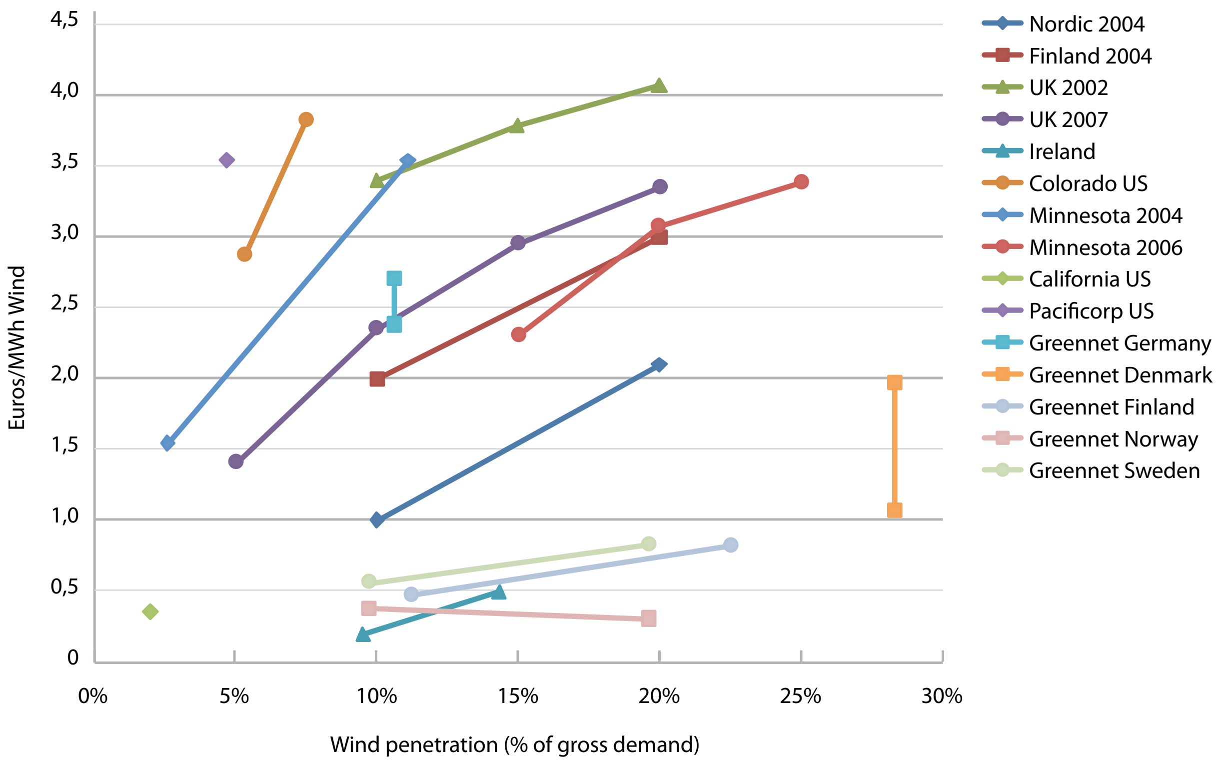
The cost of varRE integration can be divided into the three categories, 1) the day-to-day cost of balancing scheduled and unscheduled drops in output, 2) investment in complementary, flexible capacity required to cover peak demand within acceptable reliability levels and 3) investment in additional transmission to connect the resource to and reinforce networks. In this context balancing costs are the focus. Transmission investment is the subject of another IEA publication, *Electricity Transmission Investments in Liberalised Markets: Trends, Issues and Best Practices* (2010).

Today, quickly dispatchable generators provide most of the flexibility resource of a power system. In other words, the cost of additional balancing performed by such plants is the best available proxy for costing flexibility. As other flexibility sources such as demand response, interconnection and storage become more widely available, the usefulness of this proxy in assessing varRE integration costs will diminish.

A number of statistical studies have been carried out to assess the additional use of existing flexible reserves in power systems to balance shares of wind power up to levels of 20 to 25% penetration of electricity demand. These studies are not investigated here in detail. Full details can be found in the references below. The studies have however been assessed and compared in the recent report of the *IEA Wind Implementing Agreement* (2009), and some summary results are presented here to provide an indication of the state of the art of integration cost assessment, which remains an extremely complex and delicate task. Readers are invited to consult the IEA Wind report or the original studies for further details.

The studies compiled by the *IEA Wind Implementing Agreement* are mostly statistical assessments that assess balancing requirements for combined variability of wind power and load, though some studies also estimate the cost of variability from dispatch simulations. Most results are based on an approach which begins with balancing without wind, and progressively adds larger amounts of wind thereafter. Figure 7.4 compiles the findings of the various studies on the impact on balancing costs of increasing wind power penetration in gross electricity demand, expressed in Euros per MWh of wind energy.

Figure 7.4: Estimates of increase in balancing costs



Source: IEA Wind (2009).

All of the studies, except Greennet Norway, suggest that balancing costs will increase with wind power penetration. Although the findings differ substantially, they suggest that balancing costs in the systems studied will remain in the range of USD 1-6 per MWh of wind power, at penetrations of up to around 20% of electricity demand. This is equal to less than 10% of the wholesale value of wind power. The rather low results from Greennet Norway illustrate the great flexibility of the Norwegian system that stems from its hydro reservoir capacity.

It is important to note that these studies are power system-specific, and results relate only to the systems studied. Again, there is no single, "one-size-fits-all" solution to varRE integration. Study methodologies differ considerably in a large number of ways, which makes their comparison and the identification of a representative number fraught with difficulty. This is one of the reasons why it is urgent to find a standard method for assessing the flexibility enhancement of power system and the concomitant cost.

For example, the marginal cost of reserves will vary from system to system depending on the types of plant available in the generation portfolio and rules governing market operation. Different levels of assumed variability and prediction error (unpredictability) will affect the commitment of flexible units. Different types of plant will be able to cope to a greater or lesser extent with increased ramp rates, more periods of only partial operation, and more starts/stops over the plant's lifetime.

Other important criteria that differ among the studies, and which give some indication as to the range of costs identified, include:

- *Different variability time periods* – For Nordic countries and Ireland, only increased variability during the operating hour is estimated. In the United Kingdom study (2002), variability up to four hours ahead is taken into account, while in the United States studies the impact on unit commitment day-ahead is also included. The Greennet study bases reserve allocation on wind forecasts that are updated three hours before delivery.
- *Capacity investment* – In the Greennet studies for Ireland and United Kingdom, only increased operational costs are estimated, whereas other studies such as Nordic and Finland (2004) also include the cost of new capacity investments.
- *Size of balancing areas* – Some studies [Greennet Minnesota (2006), and Nordic (2004)] incorporate power exchange with neighbouring markets to reduce reserve costs, while others (California, Colorado, Finland, Ireland, PacifiCorp, Sweden and the United Kingdom) do not. The two Minnesota studies demonstrate the advantage of larger balancing areas: reduced costs in the 2006 study reflect an increase in size. The same effect can be seen in comparing the Nordic and Finland studies (2004), with higher costs seen when Finland is considered in isolation.
- *Deployment in adjacent markets* – Greennet results for Denmark and Germany reflect different reserve costs depending on the extent of wind power deployment in Finland, Norway and Sweden, the higher cost reflecting 20% deployment in those countries.

It is interesting to note that balancing costs in the Minnesota study (2006) suggest a non-linear link between wind energy penetration and balancing costs. A more detailed assessment of the study would be required to clarify the reason for this result, which is beyond the scope of our current study. An initial analysis suggests, however, that the deceleration in the rise of balancing costs between 20% and 25% penetration of wind power may reflect the relationship between Minnesota State and the wider Midwest Independent System Operator (MISO) balancing area, of which Minnesota is a part. In addition, there is the effect of per-unit smoothing of variability due to the increasing number of wind energy units on the system. In the study, intra-hour balancing requirements are assumed to be covered in-state, while hourly variability can rely also on exchange within the larger MISO area. As wind penetration rises, assuming additional in-hour variability continues to be covered by sufficient in-state reserves (at higher cost, but with lower incremental variability). If additional hourly variability instead would be balanced over the wider MISO footprint, at a more constant cost, given the deep pool of MISO reserves, then a deceleration in overall balancing cost might indeed be seen over this penetration range. It is important to note also that no wind power production was assumed outside of Minnesota, meaning that in this study generation in the rest of MISO had no other wind to balance. This is, of course, an important simplification.

In the United Kingdom study (Strbac, G., *et al.* 2007) a similar deceleration in the rise in balancing costs is observed. The absolute magnitude of the reserve (due to wind variability) continues to increase with the rise of wind penetration in the system. However, the rate of increase in reserve requirements is not linear and decreases with the increase in wind penetration.

This is because the study takes into account increasing diversity in the wind resource as penetration increases. In general, diversity results in decreasing synchronisation of the output of wind power plants.

7.5 Power system adequacy

No power plant can be guaranteed to be available all the time, as there is always the risk of technical failure. To remain within acceptable economic limits most power systems operate with a targeted level of reliability, which will reflect an acceptable probability that a certain amount of load will run the risk of not being served for a certain proportion of the time. For example, the system reliability level may be 99%, meaning that for around 100 hours per year (one year corresponds to 8 760 hours) there is a risk that demand will exceed supply and the shortfall will need to be imported.

In the context of targeting a specific level of reliability, the "capacity credit" measures the amount of load that can reliably be ensured by a power plant, an important element in the long-term planning of reserves. The capacity credit of varRE power plants is often expressed as the proportion of the same capacity of dispatchable plant that can be reliably substituted by a varRE plant.

Although conventional plants will have periods of downtime for maintenance, they can be relied upon to a greater extent to generate electricity on demand because they are based on energy sources that can be stored. In contrast, a single wind power turbine cannot be relied upon to generate all of the time as it relies on an energy source that cannot be stored. A single wind turbine cannot be expected to generate more than 80% of the time, and even then for much of the time below its rated capacity.[1]

The effect of geo- and techno-spread smoothing is to increase the capacity credit of varRE plants, so that over the whole power system a certain proportion can be expected to be in operation at any given time. The IEA Wind 2009 report has compiled the results of a number of studies to assess capacity credit, demonstrating that wind power can indeed provide some additional load carrying capability. Again, however, the range of values is very large, reflecting wide-ranging differences among power systems.

At very low penetrations, the study suggests that the capacity credit is roughly equal to the average power produced by wind. However, the capacity credit decreases more or less linearly with penetration. At a 20% penetration rate, an indicative capacity credit of 25% would be typical for a power system with a very strong wind resource, where wind output is highly correlated with demand, or where a significant geo-spread smoothing effect on variability could be observed. A lower value of 10% might be found in small systems with a lower quality of wind resource, smaller turbines or lower output correlation with demand (IEA Wind, 2009).

The lower capacity credit of wind power plants is sometimes represented as a cost. This cost is calculated as the difference between capacity credit for wind and the (higher) capacity credits of conventional plant. At high varRE penetrations, additional flexible generation capacity will be required, if flexibility cannot be sourced from other sources discussed above, such as demand response. However, such capacity is likely to be needed for relatively short periods of time, to cover peaks in demand, measured in terms of hours per year. It is likely to be best supplied by such generators as open cycle gas turbines with relatively low investment costs, which should be the basis for any cost calculations.

1. This is neither its capacity factor, nor its availability, but the amount of time a single turbine can be expected to be generating (at anywhere between minimum and rated output). "Capacity factor", in contrast, is a measure of the actual energy production divided by the maximum theoretical energy production per year; while "availability" represents the amount of time that a plant is technically available for operation (i.e. not off-line for maintenance).

Studies illustrated in Figure 7.4

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Ilex Energy, Strbac, G. (2002), *Quantifying the system costs of additional renewables in 2020*. DTI, 2002. Available at: http://www.dti.gov.uk/energy/developep/080scar_report_v2_0.pdf.

Strbac, G., A. Shakoor, M. Black, D. Pudjianto and T. Bopp (2007), "Impact of wind generation on the operation and development of the UK electricity systems", *Electrical Power Systems Research*, Vol. 77, No. 9. Elsevier Publisher, Netherlands, p. 1214-1227.

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EnerNex/WindLogics, (2004), *Xcel North study* (Minnesota Department of Commerce). Available at: www.state.mn.us/cgi-bin/portal/mn/jsp/content.do?contentid=536904447&contenttype=EDITORIAL&hpage=true&agency=Commerce.

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PacifiCorp, (2005), *Integrated Resource Planning*. Available at: www.pacificorp.com/Navigation/Navigation23807.html.

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IEA (2008), *Empowering Variable Renewables: Options for Flexible Electricity Systems*, OECD/IEA, Paris, France. Available on line at www.iea.org/g8/2008/Empowering_Variable_Renewables.pdf.

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IEA Wind (2009), Holttinen, H., *et al.*, *Final Report, Phase One 2006-2008 Design and operation of power systems with large amounts of wind power*, VTT, Finland. Publication available at www.ieawind.org/AnnexXXV/Task25_Publications.html.

ISET (2006), *Wind Energy Report*, Institut für Solare Energieversorgungstechnik, Kassel, Germany. Available at http://reisi.iset.uni-kassel.de/pls/w3reisiwebdad/www_reisi_page_new.show_page?page_nr=352&lang=de.

Financing issues

This chapter discusses a number of financial issues pertinent to the interpretation of the results obtained in Part I. Without claiming completeness, it will elaborate on different issues such as different notions of cost, discount rates and investment risk. In particular, it will look at different factors affecting the cost of financing, such as the role of fiscal policies, the impact of the recent financial crisis, exchange rates and electricity price volatility. Overall the chapter should provide an introduction to issues that require personal judgement based on perceptions of the future and risk preferences rather than any definite statement on the "right" decision, which more often than not does not exist in any definite manner. The chapter will conclude with a discussion of the role of public-private partnerships, export credit guarantees and support by multilateral institutions in this context.

8.1 Social resource cost and private investment cost: the difference is uncertainty

Before entering into a detailed discussion of the different issues pertaining to the financing of the different technology options presented in this study on electricity generating cost, it is useful to recall the particular cost concept underlying the calculations presented in Part I. The average levelised lifetime costs for baseload power generation calculated in this study indicate the *social resource cost* of a particular technology over its operating lifetime expressed in USD per MWh of electricity. This notion of social resource cost is net of all forms of government interventions, such as taxes or subsidies that would impact the calculations for an investor. A private investor also needs to consider (and pay for) certain additional risks, such as the risk of default, which is not part of social resource costs. In the following, we will briefly explain the two notions of cost in order to allow the reader to form their own view when interpreting the data.

"Social resource cost" is the opportunity cost a society has to forego when it undertakes an investment in a specific technology. The key aspect here is the assumption that all risk is captured in the discount rates. The additional uncertainty that goes beyond the risk captured in the discount rates and needs to be faced by an investor operating in competitive markets, in particular private investors, is not the subject of this study, although Chapter 10 will enumerate some of the key issues. In practice, private investors face higher financing costs than public investors since creditors demand extra insurance for the risk of default.[1]

1. There is an additional reason, why public investors have often lower financing costs. Kenneth Arrow and Robert Lind showed in their 1970 paper that public investments can use the risk-free discount rate since the number of individuals over whom the investment risk is spread is very large (Arrow and Lind (1970). When the risky project is only a small part of income, the risk associated with it becomes negligible. An important additional assumption is that the return of the investment be independent of all other income, an assumption that needs to be verified case by case. It holds for an investment into an individual plant but would be less true for a large-scale electrification programme. The Arrow-Lind theorem has been challenged on the grounds that (a) public investment can displace private investment and should thus be evaluated according to the same discount rate and (b) that private investors today can diversify easily through mutual funds such that additional benefits from risk-spreading are negligible. The extent to which these counter-arguments are considered acceptable varies widely. In particular, the question to which extent public and private investments are substitutable is answered differently in different countries.

For the purposes of this study, it means that when using the term "social resource cost" we treat the investment in question as if there was no price risk. The very notion of the levelised cost methodology implies the existence of stable electricity prices over the whole lifetime of the project. Nevertheless, the two discount rates used in this study (5 and 10%) provide rough indications of different levels of intrinsic risk (see below). From Chapter 2, we recall briefly the basic equation on which the calculations of the levelised costs of electricity (LCOE) are based. The notion of levelised average lifetime costs or levelised costs of electricity corresponds to the price that would equalise discounted benefits and discounted costs and thus would allow an investor to break even.

In the equation below, the left-hand side shows the total discounted value of the electricity produced in year "t" ($Electricity_t$) and sold at the constant break-even electricity price ($P_{Electricity}$) and the right-hand side the total discounted costs. The risk-free discount rate is "r" and discounting takes place on an annual basis:

$$\sum_t (Electricity_t * E\text{-}Price * (1+r)^{-t}) =$$

$$\sum_t [(Investment_t + Maintenance_t + Fuel_t + Carbon_t + Decommissioning_t) *(1+r)^{-t}].$$

This implies that

$$\sum_t (Investment_t + Maintenance_t + Fuel_t + Carbon_t + Decommissioning_t)*(1+r)^{-t}/\sum_t(Electricity_t*(1+r)^{-t} = E\text{-}Price = LCOE.$$

By and large, this approach of estimating social resource costs to determine choices between alternative investments in the power sector has served well for decades during which electricity was produced by regulated utilities, that is, vertically integrated monopolists overseen by a regulatory commission. Regulators would set prices for defined periods and thus remove price risk within each regulatory period. While the level of demand and certain cost elements such as fuel prices would remain uncertain, allowances to adjust final prices could be made that would neutralise such risks. The risk-free rate is generally considered corresponding to the rate of return on long-dated government bonds issued by governments with very little probability of defaulting (Germany or the United States, for instance). The index-linked USD 30-year Treasury bond in summer 2009 thus offered a real annual return of 2.2% (net of inflation), substantially lower than the real returns of 5 and 10% used in this study.

Matters change radically when considering investments in competitive markets with uncertain prices. To cope with market risks will require higher rates of return on investment, which means higher costs.[2] First, even the most credit-worthy investors are required to pay a premium over the risk-free rate for their credits. The longer the timeframe, the higher is the premium. In addition, they will have to make provisions for uncertainty in electricity prices. A sudden drop in prices can turn a promising project into a substantial loss (European electricity prices, for instance, halved during the latter part of 2008). Due to such uncertainty, risk-averse investors demand *average* returns higher than the risk-free rate. That means, an investor who will have a zero return on investment if prices are low and a return of 12% if prices are high (and there is a fifty/fifty chance of prices being high or low) will not demand an average return of 6% but of, say, 8%. Through the mark-up of 2%, the difference between the average and the required return, investors look to compensate themselves for the riskiness of their investment.

The riskier the investment, the higher will be the mark-up over the average return. Needless to say, higher discount rates (and correspondingly, interest rates) have a direct impact on the overall cost of projects. To the extent that they reflect the uncertainty faced by individual investors, financial costs are always higher than social resource costs, which do not need to take the cost of uncertainty into account.

2. An alternative course would, of course, be to buy insurance. The cost of insurance, however, would still require that investors demand a higher rate of gross return (profit) on their investments.

However, the difference between social resource cost and private financial cost should not be overplayed. Many investors in electricity markets are large, diversified, frequently international, companies that operate in different market environments and have substantial abilities of their own to pool returns from a large number of projects and to spread the risks over large numbers of investors. In addition, even if prices have grown more volatile in recent years, underlying demand is fairly stable. Indeed electricity demand has grown in most markets relatively steadily, with the notable exception of 2009. Capital markets are, of course, aware of this and generally electric utilities have easy access to credit and benefit from some of the lower costs of borrowing in the market.

In the electricity sector, the difference between social resource cost and financial investment cost (including risk) can essentially be traced back to the question of price volatility.[3] Nevertheless, rates can vary in response to a number of additional risk factors that are specific to technologies. This has raised the question whether all technologies should use the same discount rate. From the point of view of an investor, the answer is probably "no", as he will form his opinion about the risks inherent to different technologies according to the weights he personally assigns to different risk factors. From the point of view of this study however, the competitiveness of different technologies is assessed disregarding the market and technology risk.

In addition to price risk, there are thus a number of other factors that can affect the riskiness of an investment in power generation. Many of these risks are in some way or other related to the regulatory or political sphere. They include:

- regulatory risk (this includes both the regulation of electricity market, environmental regulations concerning climate change and other emissions and safety regulations);
- political risk at the national and the local level pertaining to the acceptability of new power generation investments;
- technological risks for new technologies such as certain renewable energies or carbon capture and storage (standardisation and design homogenisation can decrease this risk);
- changes in fiscal policy, in particular with respect to income taxes, which affect, in particular, technologies with a high proportion of capital expenditures such as renewable or nuclear technologies;
- high amounts of capital-at-risk and high ratios of fixed or sunk costs to total costs ratios that limit flexibility in case that market conditions change;
- changes in input prices, which will affect, in particular, technologies relying on fossil fuels;
- safety and human health risks (air-borne pollution, radiation leaks, site contamination, major accidents);
- availability of adequate human resources, skills and knowledge (especially for advanced technologies such as nuclear);
- proliferation risk for nuclear fuels and technology;

3. See also Chapter 9 on "Levelised costs and the working of actual power markets". Price volatility affects different technologies in different ways. In liberalised electricity markets, prices are set by the cost of the marginal fuel, which means the fuel with the highest variable cost, which is frequently gas. Given that the cost of the input (gas) and the price for the output (electricity) are thus closely correlated, the profitability of gas-fired power plants can remain fairly stable even in markets with high volatility. This is not all the case for high fixed cost and low variable cost technologies such as nuclear and renewables, whose profitability is heavily affected by changing prices for electricity. This is certainly the most relevant issue in distinguishing the calculations of social resource cost for baseload power generation under an assumption of stable prices that is undertaken in this study from the cost-benefit calculations a private investor in liberalised markets would undertake.

- security of supply risks for the availability of certain inputs, in particular gas in some regions;
- availability of long-term options for decommissioning, waste storage and site restoration (especially for nuclear, carbon capture and storage, and brown coal).

The above list of the different risks faced by investors in power generation is daunting. It also shows that not all technologies are affected by all dimensions of risk in an identical manner, although it is obvious that no technology does better or worse than the others on all counts. However, despite the real and important concerns that are behind the different items reflected in the list, their collective impact should not be over-estimated. In well-run stable democracies, policies and (by and large stable) regulations are in place to address virtually all of these issues in a manner reflecting carefully balanced long-term compromises negotiated through the political and the institutional process. The exception is, of course, the price risk for fossil fuels, in particular gas. While fuel price risks can to some extent be hedged in many OECD markets, this becomes expensive beyond one or two years. At the end of the day, however, the one risk private investors in power generation in an OECD country is likely to worry about most, and which is also most likely to affect their discount rate and financial cost, remains the price risk for their output in competitive electricity markets, particularly in an environment of slow and uncertain demand recovery over the next years.

Finally, there is an additional consideration to the financial structure of energy investments that depends directly and immediately on government policy that merits extra mentioning. Investors essentially have two options for generating the funds needed to finance a project: debt and equity. Debt means getting credit from a bank. Equity means selling shares in the project to capital markets. Debt is less risky for the lender, due to higher seniority in case of bankruptcy, more difficult access for the borrower and stable interest payments. The tax treatment of debt is also frequently more favourable, i.e., interest is considered a cost and is thus tax deductible while dividends are not. Equity instead is wiped out in case of bankruptcy and its level varies with profits (see also the specific discussion below). Necessarily lower-risk debt thus requires lower interest rates than higher-risk equity. The full financial cost of an investment will thus be determined by the interest rates of debt and equity weighted by their respective shares in the financing mix, generally known as the weighted average cost of capital (WACC). The underlying algorithms of *Projected Costs of Generating Electricity* calculate financing costs for one single interest rate at a time (either 5% real, i.e. net of inflation, or 10% real), without specifying any particular split between debt and equity finance. Any assumption will do, whether 100% debt, 100% equity, or any proportion of the two, as long as the weighted average of their returns amounts to either 5 or 10%.

Without going into the subtleties of corporate finance a real-world investor would have to deal with, one can make the following broad statements in the context of *Projected Costs of Generating Electricity.*[4] The 5% real discount rate can be considered as the rate available to an investor with a low risk of default in a fairly stable environment. Traditionally, this was thought of as the risk faced by a public monopolist in a regulated market. However, the same rate may apply to a private investor investing in a low-risk technological option in a favourable market environment. The 10% real discount rate instead was considered as the investment cost of an investor facing substantially greater financial, technological and price risks. Any of the qualitative risk factors mentioned above might contribute to this higher rate of discount. Next to price risk, technology risk, the risk of investing in first-of-a-kind plants and in new and unproven technological options ranks among the most important factors driving up discount rates for investors in the power sector in OECD countries.

4. Such a study would need to include among other issues accounting conventions, tax laws, the availability of investment incentives, the structure of electricity markets and demand etc. for one particular market and technology. It could never produce comparable results for a number of different technologies across a number of countries according to simple, harmonised assumptions.

8.2 The role of corporate taxes and the coherence of fiscal and energy policy

The impact of corporate taxes on investment decisions in power generation has received increased attention in recent years (see NEA, 2008; IEA, 2006; MIT, 2009). The argument is that high corporate tax rates constitute *de facto* a tax on capital and thus penalise capital-intensive technologies. A direct consequence of this argument is the question whether fiscal policies and energy policies are coherent, given the fact that carbon-free or carbon-reducing technologies such as nuclear energy, carbon capture and sequestration, or renewable energy are highly capital-intensive.[5]

The issue is, however, far from straightforward. It is even less so in the context of a study interested in the social resource cost of different technologies using a methodology built around the notion of levelised average lifetime costs and this for two reasons:

1. First, taxes are transfer payments and they thus affect neither overall economic efficiency, nor social resource costs of a technology. From a static point of view, abstracting for the moment from dynamic incentives which do play a role in practice, societies as a whole will not be any richer or poorer whether taxes are high or low. The distribution between providers of capital and the government budget will, of course, change. This, however, is a zero sum game and the total amount of funds available for consumption and investment, or electricity production for that matter, will not change.[6]
2. Second, the methodology of calculating levelised average lifetime costs is built around the equivalence of the present value of total discounted costs and the present value of total discounted revenues. Levelised average lifetime costs are thus, by definition, identical to the real constant price of electricity ensuring this equality. In this approach, investors precisely break even over the lifetime of a project, even if there are, of course, losses during construction and profits during operation. This, however, means that in an ideal tax system, where investors can set off profits against costs without constraints, there are no net profits to tax.

Why then study the impact of corporate taxes, nevertheless? The counter-argument to the first point is that the IEA/NEA studies on the *Projected Costs of Generating Electricity* do not look at the social resource costs of generating electricity in an abstract and absolute manner. These studies have always been interested also in the comparative private costs of different technologies, albeit in a prudent and very limited manner. Introducing the question of taxes in the evaluation of a project means introducing a private investor point of view, even if indirectly. But so be it, *Projected Costs of Generating Electricity* is not designed to be a methodological handbook but intended to provide pertinent information on the relative costs of different technologies. And while corporate taxes do not affect total welfare on an aggregate, macroeconomic level, they do affect the costs of a private investor having to choose between different technologies. This is why some information on the impact of corporate taxes is included in this study.

The counterargument to the second point is more subtle and pertains to the specific forms of corporate financing an investor in an electric power plant might be able to arrange. It also requires distinguishing an *ex ante* and an *ex post* view of costs and the calculation of corporate profit. First, the *ex ante* view. If the investor would finance their plant through bank loans or by issuing corporate bonds at a fixed interest rate and if the price they received for the electricity corresponded indeed to their levelised average lifetime costs, then accumulated corporate profits

5. The relationship between relatively high capital-intensity and low carbon emissions is very general. It is easy to understand intuitively if one considers that fossil-fuel-based technologies have both high variable costs, namely their fuel costs, and high carbon emissions. In other words, the carbon content of fossil fuels which is, of course, valuable for power production, raises both variable costs and carbon emissions. Moving away from carbon emissions implies lower variable costs and relatively higher fixed costs.

6. Of course, the economy is dynamic – taxes can and do affect economic efficiency and investment.

over the lifetime of the project would be zero. If losses during construction can be offset against profits during production, total corporate taxes at any tax rate would indeed be zero and not affect the costs of the investment.

Only in rare cases, however, will an entrepreneur be able to arrange for 100% of debt finance and therefore the project developer will need to resort to capital markets and sell a share of their project to equity investors. These investors are not entitled to a fixed return on their investment but have a claim on their share of the residual profits once all other factors of production have been paid. This is the *ex post* view. For simplicity, one can assume that half of investment costs have been financed by debt and the other half by equity. Once the interest on the debt has been paid, there are profits left to be turned over to shareholders. Before that, however, governments will tax these profits, say, at a rate of 40%. This means the amount of money available for shareholders is reduced by 40%. Since equity shareholders, however, have very clear ideas of much they would like to earn (otherwise they will take their money elsewhere), total gross profits will need to be correspondingly higher to be able to pay them. This, however, raises the total lifetime costs of the project.

How corporate taxes can affect the cost of a project

Take a new nuclear power plant with 1 500 MW of capacity and a total investment cost including contingency of roughly USD 6 billion. At a fixed rate of interest of 5%, its levelised average lifetime cost over sixty years of operations is USD 47 per MWh. Once one assumes, however, a 50-50 split between debt and equity finance and a 40% corporate tax rate, the tax adjusted required return, i.e. the average weighted real cost of capital inclusive of tax will rise to roughly 6% ($0.5 * 0.05 + 0.5 * 0.05 * 1.4 = 0.06$). This will increase the levelised average lifetime costs to USD 53 per MWh.

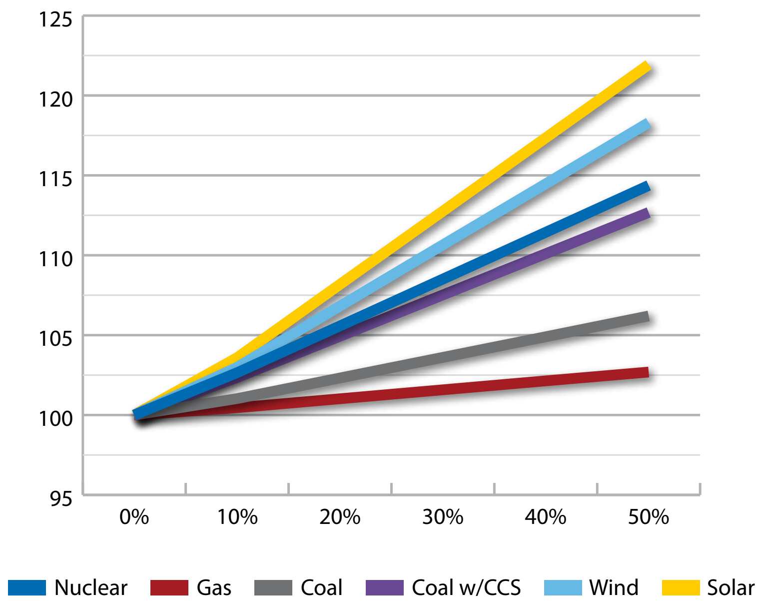
This simple example shows how corporate taxes increase the cost of capital and are in fact equivalent to an increase in the interest rate that investors faces. In this example the tax on income from bonds is zero but can of course readily be integrated into the calculations. This simple story can easily be complicated. For instance, the higher tax on equity might induce investors to increase the portion of debt financing. While this would decrease the cost of capital in a first step, higher demand for bonds and increased risk for share-holders due to higher leverage might drive up the capital cost in a second step. The net effect is impossible to predict and empirical studies on this subject are inconclusive.

This chapter focuses exclusively on the direct effect of how corporate taxes can increase the cost of capital-intensive technologies disproportionately. Nevertheless, as far as policies in the electricity sector are concerned, corporate taxes should not be looked at in isolation.

Tax policies must be part of a broader set of policies aiming to reduce the cost of capital for capital-intensive, low-carbon technologies. Stable environments for regulation and prices are a critical part of such policies.

Once the different conceptual issues surrounding corporate taxation have been clarified, their calculation is straightforward along the lines provided in the example above. The two graphs below (Figures 8.1 and 8.2) show the relative impact of corporate taxes at 0, 10, 20, 30, 40 and 50% at first for a real discount rate of 5% and then for a real discount rate of 10%. The results have been normalised in order to allow for easy comparison of the relative impact of corporate taxes; the graphs do not contain any information about absolute cost levels.

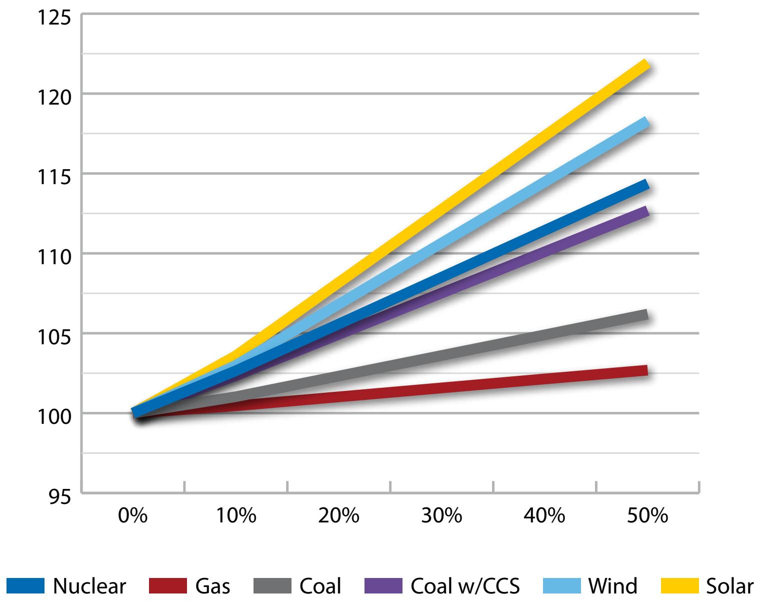
Figure 8.1: Impact of corporate taxes at 5% discount rate and 50% equity finance
(LCOE without corporate tax = 100)



Unsurprisingly, the more capital-intensive technologies such as nuclear, solar, wind or coal with CCS are more heavily affected by increases in corporate taxes, i.e. proportionally their costs increase more quickly than those of less capital-intensive technologies such as coal and gas. The fact that nuclear is more heavily affected than either solar or wind has to do with the relatively longer construction periods. The interest that needs to be paid during construction increases with the real costs of capital, which in return is a function of the corporate tax rate. Nevertheless, the overall impact is limited. Even with a very high corporate tax rate of 50%, the total impact on costs would only be 15%. Corporate tax rates in OECD countries varied between 12% (Ireland) and 40% (Japan), with a weighted average of 28% in 2006. Taking into account corporate taxation would thus increase the cost for a private investor in nuclear energy by roughly 10%, while the cost for other technologies would increase between 1% and 10%.

The situation does not change dramatically when considering a basic real discount rate of 10%. Including corporate taxes at the average OECD rate would increase the cost of nuclear energy by roughly 15% and those of other technologies between 2% and 10%.

Figure 8.2: Impact of corporate taxes at 10% basic discount rate and 50% equity finance
(LCOE without corporate tax = 100)



From the point of view of private investors, corporate taxes are thus a significant but not decisive element in their cost calculations. As has been said above, the question of corporate taxes is a sub-question of the real cost of capital or the discount rate that investors have to use in calculating the costs and benefits of their investments. There is no way around the simple fact that the costs of capital-intensive, low-carbon investments are very sensitive to discount rate changes. High corporate taxes further magnify this impact.

8.3 The impact of the financial and economic crisis

From the preceding discussion, it is evident that interest rates and hence the discount rates investors use (and, by extension, issues such as risk perceptions or corporate taxes) have a major impact on the absolute and relative costs of investments in power generation. It is thus natural to ask whether the recent financial and economic crisis will have any bearing on the level of interest rates. The easy answer is that most investments in power are very long-lived. In this context the upheaval in financial markets during the end of 2008 and the beginning of 2009 will thus be a downward correction to the scenarios on which investors base their decisions as demand return to its normal growth path over the medium to longer term.

The easy answer implies that the recent financial and the ongoing economic crisis might not affect decisions in energy investment over the long term. This may be correct. Nevertheless, there is slightly more to say about the current situation in the market for government bonds where interest rates are set. This market is currently characterised by two opposing tendencies. Due to the massive injection of liquidity by central banks ("quantitative easing", colloquially known as "printing money") in the wake of the credit crunch, the short-term interest rates at which banks can borrow from the central bank are very low. The yield on the benchmark two-year US government bond was only 1% in October 2009. This allows banks to borrow funds cheaply, which helps them to rebuild their balance sheets and their profits.

This, however, does not mean that either long-term interest rates in the bond market or commercial interest rates are equally low. Long-term interest rates are in fact substantially higher with a yield of 3.7% for the ten-year US government bond and 4.7% for the 30-year bond (both, February 2010). It also needs to be kept in mind that these are nominal figures. In order to compare the nominal yield on the 30-year bond with the 5 and 10% real discount rates used in *Projected Costs of Generating Electricity,* an allowance for inflation needs to be made. If central banks are able to realise their declared objective of 2% inflation over the long term, a corresponding figure of 2.2% (real) for long-term government financing would need to be used. In fact the real yield for the 30-year inflation-indexed bond is currently 2.1%, which must be considered the real cost of long-term financing for a riskless asset.

This substantial difference between short-term and long-term rates can be explained by the fact that investors do not expect central banks to maintain their quantitative easing policy beyond the short term (which is in fact not sustainable), and that they will phase out these policies, which will see interest rates raising. They are comforted in this analysis by the fact that governments, who have borrowed heavily during the crisis, will have to finance their deficits by drawing on the bond market, which, of course, will also drive up interest rates.

In December 2008, in the midst of the financial crisis, the nominal rate of the 30-year bond was 3.2%, while in December 2007, the rate was slightly higher than today at 4.3%.[7] One thus really cannot say that markets expect an environment with permanently higher interest rates to prevail after the crisis. Perhaps the easy answer that the crisis will not have any long-term effects on investment conditions is the correct one after all. Even the impacts of increased regulatory oversight are difficult to gauge as increased constraints due to higher capital requirements will be off-set by decreased systemic risk due to the fact that defaults will become less likely.

An additional question is, however, at which rate banks will pass on their own borrowing costs to investors such as utilities. The spreads for long-term corporate bonds over US government bonds varies with the rating of the company, its risk of default. In December 2009, the average yield on US investment grade corporate bonds (rated BBB or higher) was 4.6%. The average yield on high-yield ("junk") bonds was 9.8%. This represents a mark-up between 0.4 and 5.6% over the risk-free rate. Factoring out inflation, real US corporate bond yields varied between 2.6 for investment grade bonds and 7.8% for high-yield bonds at the end of 2009. The 5 and 10% real rates of discount used in this study are thus on current figures quite realistic and not particularly low indicators for the cost of debt financing of power generation projects. An IEA analysis of Summer 2009 on the total cost of financing (cost of debt and equity financing combined) for US electricity companies showed that the WACC was 10.5% in fourth quarter of 2008, which is quite consistent with the findings on debt finance above.[8]

At least as important as the impact on financial markets and the costs of capital is the impact of the crisis on the real economy, that is electricity demand, which has already led to a number of investment decisions having been rescheduled or cancelled. For the first time since 1945, global electricity consumption fell in 2009 by around 2%. Since electricity is a non-storable good produced with a rather rigid supply structure, any change in demand feeds immediately through into prices. European wholesale power prices, for instance, are roughly half of what they were a year ago. Such facts cool the ardour of the most committed investor. Add a halving of carbon prices into the mix, and it is unsurprising that in the absence of any policy action or investment incentive in the OECD the IEA foresees a 20% decline of investment in renewable energies in 2009.[9]

7. The information on government and corporate bond rates comes from www.ustreas.gov, www.bloomberg.com and www.ft.com.

8. See IEA (2009a) and IEA (2009b).

9. According to WEO 2009, in late 2008 and early 2009, investment in renewables-based generation fell disproportionately more than in other types of generating capacity. For 2009 as a whole, it could drop by close than one-fifth. Without the stimulus provided by Government fiscal packages, it would have fallen by almost 30%.

There are two other financial issues that might be considered added risk factors for investors, which are exchange rate volatility and inflation. While occasionally mentioned as risk factors, their actual impact is likely to be limited. Exchange rate volatility is probably the one risk that international financial markets are best equipped to deal with. Loans can be contracted in any major currency, both cost and revenue streams can be hedged over several years at least. While such hedging comes at a cost, the markets on which it takes place are liquid and highly competitive. For commodities traded in freely convertible currencies such as oil, investors are thus required just to pay the competitive rate for ensuring against exchange risk. The issue might be slightly different for commodities such as gas, which in certain cases are traded in less convertible currencies. For electricity, finally, the issue does not exist on the output-side since it is usually produced and consumed locally. Inputs again are usually traded in highly liquid currencies.

Regarding inflation, everything depends on the expectations concerning future inflation. Also on this issue, the market for government bonds provides key insights. An inflation-indexed 30-year US government bond had a real yield of 2.1% per year (February 2010). Comparing this to the yield of 4.7% of the standard 30-year bond indicates that the market expects inflation to be around 2.5% per year over the next 30 years. This is close to the average of the past years rather and neither reflects deflation due to the crisis or higher inflation as a result of measures employed to combat the crisis. While the magnitude of recent policy interventions was unprecedented and the long-term impacts of high long-term levels of government debt are testing uncharted waters, bond markets remain remarkably sanguine.

Thus neither exchange rate volatility nor inflation is currently deterring investors in the power sector. By far, the greatest uncertainty now is future electricity demand in OECD countries. Independent of the financial and economic crisis, aggressive policies in OECD countries to reduce carbon emissions and increase energy efficiency will ensure that this uncertainty will continue. There is the distinct possibility that the crisis will have a "ratchet effect", i.e. that behavioural changes due to greater economic uncertainty and declines in income will persist even when economic conditions improve. While this would be welcome in many respects, it would increase uncertainty for investors in electricity generation. Crisis or no crisis, managing investment portfolios in the power sector and deciding on the construction of new power plants will become more challenging in the years to come.

8.4 Options for improving investment conditions in the power sector

The importance of managing uncertainty makes a strong argument for exploring the possibilities of public-private partnerships in order to improve the investment conditions in the electricity sector in general and for capital-intensive low-carbon technologies such as nuclear, renewables or carbon capture and storage, in particular. Of course, no one seriously argues for a return to an all public provision of electric power with its organisational and managerial inefficiencies, its inertia and its preservation of special interests. The momentum towards liberalised electricity markets in OECD countries cannot be reversed.

However, even within the broad context of competitive electricity markets, there is a case to be made that the public sector has a role to play in enlarging the choices available to private decision makers. This role must necessarily focus on the reduction of uncertainty in order to enable investors to benefit from lower costs of capital. There are two fundamental strategies to go about this task. First, the overall policy framework for the coming decades must be as stable and as transparent as possible. The commitment of European Union countries to reduce their greenhouse gas emissions by at least 20% by 2020 or the commitment of G8 leaders at their recent summit in L'Aquila (Italy) to halve global greenhouse emissions by 2050 (which both implicitly set a price for carbon emissions) provide indeed clear policy signals. The remaining uncertainties are, of course, enormous and it would be desirable that future policy actions aim at providing further clarity on the precise implementation of such ambitious targets.

The second strategy consists of directly aiming at lowering the cost of capital for investments in the power sector, with or without conditionality on carbon performance. At the national level, OECD countries can, for instance, provide loan guarantees as an incentive measure that would lower the cost of capital – since repayment risk would be reduced. In addition, such a measure would be compatible with the workings of competitive power markets.[10] At the international level and in emerging markets multilateral institutions such as the World Bank or the development banks for Africa, Asia and Latin America can also facilitate investment by reducing risk through loan guarantees.[11] Export credit guarantees already play a role in this context. The recent revision of the OECD Nuclear Sector Understanding (NSU) of the Arrangement on Officially Supported Export Credits that entered into force on 1 July 2009 is, for instance, one step in this right direction.

The case for improving the financing context and lowering discount rates whenever possible is warranted also from a sustainable development perspective. If sustainability is indeed in the words of the Brundtland definition about "development that meets the needs of the present without compromising the ability of future generations to meet their own needs", then the future should not be discounted too steeply. Ensuring a stable investment environment with low real interest rates is indeed one of the most effective steps to ensure sustainable development in the electricity sector and beyond.

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10. A number of OECD countries are currently moving in this direction. In the United States, for instance, the Department of Energy has authority to issue USD 100 billion in loan guarantees for investments in the power sector. Provisions in Energy Bills currently debated in Congress to create a Clean Energy Deployment Bank would leverage this amount by a factor of two to three.

11. While these international development banks could certainly provide useful roles in reducing investment risk, they cannot be drawn upon as an exclusive source of finance, since they do not treat all technologies alike. The African Development Bank, the Asian Development Bank, and the Inter-American Development Bank have policies in place not to finance nuclear energy projects. The European Bank for Reconstruction and Development provides nuclear safety grants but does not finance new nuclear reactors. Finally, the World Bank has no written policy on nuclear energy but has not financed nuclear projects in recent years.

Levelised costs and the working of actual power markets

Recent IEA work suggests that the power sector can significantly contribute to addressing the twin challenges of energy security and environmental sustainability. Currently, the OECD generation mix is composed of about two-thirds of fossil-fuelled generation and one-third of renewables (mostly hydro) and nuclear combined. At their latest meeting in October 2009, the 28 IEA energy ministers have reaffirmed their determination to accelerate the transition to a secure, competitive and sustainable energy future. More than ever, the power sector is under significant pressure to achieve higher energy efficiency and shift towards cleaner and low-carbon generation options. This context provides great opportunities for innovation, technology development and investments in the power sector.

The IEA *World Energy Outlook 2009* projects in its Reference Scenario that over the period 2008-2030 OECD countries need to invest USD 5 694 billion in the power sector, including USD 3 292 billion in generation and USD 2 402 billion in transmission and distribution. Furthermore, the OECD+ countries (which include member countries of the EU that are not members of the OECD) need to invest a total of USD 3 586 billion in generation over the period 2010-2030 in order to limit the concentration of greenhouse gas emissions in the atmosphere to 450 parts per million (ppm) of CO_2 equivalent.

Since electricity is vital to modern economies and consumer well-being, power sector investments and their impacts on electricity costs and prices have been a subject of increasing interest to industry, governments and policy makers. A key role for governments is to ensure that investments are realised where and when they are needed, and with the right technologies, contributing to energy security and climate protection while minimising the impact on electricity costs.

This chapter attempts to bridge the gap between levelised cost of electricity (LCOE) values and electricity market realities with the view to develop an understanding of what LCOE methodology and its derived results mean to investors and policy makers. It elaborates on the uncertainties investors are facing and the working of actual power markets. It also discusses the investment decision process taking into account the factors associated with power plant investments not included in simple cost accounting.

Although by no means comprehensive, the LCOE methodology and derived results, if properly interpreted and used in conjunction with other analytical instruments, can be an important tool for assessing power generation investment as well as for policy formulation.

9.1 Use and limitations of LCOE

The levelised cost approach is a financial model used for the analysis of generation costs. It focuses on estimating the average levelised costs of generating electricity over the entire operating life of the power plants for a given technology, taking into account main cost components namely capital costs, fuel costs and operations and maintenance (O&M) costs. This analytical framework is flexible and allows specific cost factors (e.g. contingency, decommissioning, carbon prices) to be considered.

The main results of the LCOE model are the levelised unit costs of electricity generation. These are average costs over the life of a project and for a given technology, based on a specific set of assumptions. Levelised costs provide important insights into the main cost factors of alternative generation options. Since many cost components vary considerably from location to location and project to project, sensitivity analyses may be performed to assess the impact of changes in key parameters on the costs of generating electricity.

LCOE methodology can be used in many applications and for many purposes, including:

- Estimating the costs of producing electricity from a new power plant or for a given technology.
- Analysing the various generation options available to investors in a given market. Since markets differ, investors can adjust the key cost parameters as well as the assumptions to reflect the local and regional market realities.
- Identifying the least cost option among alternative generation investments.
- Evaluating the impact of market changes on generation costs.
- Assessing the cost structure of various generation options.
- Assessing the impacts of changes in key assumptions, including key policy parameters such as carbon prices, on unit costs.

Under this model, cost cash flows are discounted back to the present (date of commissioning) using assumed discount rates. These discount rates essentially reflect consideration of the opportunity cost of capital. Discount rates can also be considered as the determinant of the required capital recovery time, i.e. the time it takes to fully recover the investment. With a higher discount rate, the capital invested will need to be recovered in a shorter time relative to a lower discount rate. It should be noted, however, that in the analytical set up of this study, the payback period is determined by technical lifetimes of different generating technologies.

For each generation option, the unit costs of generating electricity are the main driver for choice of technology. The accuracy and usefulness of estimated unit costs depend to a large extent on good assessments of their cost components – investment, fuel and O&M costs. It also depends on how close to reality the main assumptions are regarding, for example, construction time, load factors, efficiency rates, years of operation. Technologies with an established track record during the phases of both construction and operation and with relatively stable costs during their lifetime are regarded as less risky. To the extent that long term, stable income can be guaranteed over a project's life, risk is further reduced. In contrast, technologies with historical cost overruns, costly delays during construction, and fuel cost volatility generate additional risks, real or perceived. Higher perceived risks would in turn demand higher rates of return on investment.

Investment costs are probably the most important parameter in any investment decision. They vary greatly from technology to technology, over time and from country to country. They are sensitive to a number of input factors such as manufacturing costs (e.g. steel), labour and other construction-related costs. Plant and equipment costs are also subject to manufacturing capacity constraints. High demand for some equipment worldwide may cause bottlenecks and put upward pressures on equipment prices (e.g. gas and wind turbines), a situation that prevailed in 2005-2008.

Nuclear power plants are highly capital intensive and require significant upfront investment currently. Plant design standardisation and modular construction can potentially lower costs per MW of nuclear capacity installed. However, except for Asia, the construction of new nuclear units has been inactive for practically around two decades in OECD countries. Due to limited recent experience with building nuclear power plants, the emerging nuclear renaissance will face a number of first-of-a-kind risks. Controlling construction costs will be essential. In this regard, the standardisation of nuclear units will be an essential tool. It would facilitate licensing, equipment supply and construction planning – all of which are crucial to cost reduction.

Furthermore, investment costs will benefit from economies of scale in both the size of each individual unit and in the number of units to be built. Licensing, construction, operation, safety management and waste management are cheaper and more efficient with a portfolio of nuclear plants compared to individual ones. Managing risks of construction costs may be the greatest challenge facing nuclear expansion. The high up-front investment costs also make construction time a critical factor for nuclear long term competitiveness. While still a challenge in countries lacking recent experience with building nuclear power plants, concerted efforts to reduce construction delays have already allowed reporting average construction times of 62 months for recent and anticipated nuclear builds in Asia, notably in China and Korea. In Finland, the construction of Olkiluoto-3 has incurred a two-year delay, however.

Solar panels, wind and gas turbines (open and combined cycle) are standardised to a great extent, with many similar plants in operation, and construction times short; they can be built within 6 to 24 months. In particular, the only OCGT in the sample (Australia) has a reported construction period of 12 months. CCGTs can be built as quickly as 18 months in ideal circumstances, but can also take up to 36 months. These technologies can be built in relatively small sizes without significantly increasing cost per kW of installed capacity. CCGTs can thus be built in stages, commissioning the gas turbine before the entire plant, and in modules, increasing the capacity in steps of 300-800 MW.

Coal plants are adapted to specific local conditions, making standardisation more difficult. Still, investment costs are relatively stable and predictable, building on the long and broad experience of vendors. Coal units are typically built in unit sizes of 300 MW to 1 000 MW. Thus, there are important economies of scale, but not as large as for nuclear power plants.

In addition to construction cost concerns, a power project also needs planning and development, and a long list of licenses and approvals is required, all varying with project, location and technology. Nuclear power projects require the longest pre-construction process, a process that also necessitates considerable investment before even knowing that the project will be realised. Public acceptability of a project is reflected in this process, and can seriously delay projects and inflate project costs.

Since it takes into account project-specific construction times, construction costs and even the first-of-a-kind risks translated into higher contingency requirements, the LCOE methodology can be a practical tool for the analysis of electricity generation costs. It provides useful insights in evaluating investments and formulating policies. However, this methodology, as with other analytical instruments, faces some real limitations, including:

A. The LCOE approach does not adequately reflect the market realities characterised by uncertainties and dynamic pricing.

B. The LCOE approach provides generation costs at the plant level and does not include the network costs of a power system.

C. The LCOE approach reveals little information on the contribution of a given technology to addressing energy security and environmental sustainability.

D. The LCOE does not indicate the relative likely stability of production costs over a plant's lifetime, and therefore the potential contribution to cost and possibly price stability.

A. Uncertainties and risks

A basic weakness of LCOE methodology is that it essentially assumes a static world in which there is no uncertainty and thus, that costs occur in the ways they are "predicted" by a fixed annual cash flow schedule. Although the LCOE approach provides an important part of the analysis of generation costs, the real market place is much more complex and characterised by multiple risks and uncertainties that are outside of the scope of the LCOE methodology. The risks of underestimation or overestimation of generation costs are inherent in LCOE estimates due to these uncertainties. Table 9.1 identifies key uncertainties and risks investors face.

Table 9.1: Main risk factors for investors in power generation

Plant risk	Market risk	Regulatory risk	Policy risk
Construction costs	Fuel cost	Market design	Environmental standards
Lead time	Demand	Regulation of competition	CO_2 constraints
Operational cost	Competition	Regulation of transmission	Support for specific technologies (renewables, nuclear, CCS)
Availability/performance	Electricity price	Licensing and approval	Energy efficiency

Source: IEA, 2007a.

Although some risks are common to all technologies (e.g. demand and policy uncertainties) the nature and degree of risks differ significantly from project to project and from technology to technology. For example, the regulatory risk may be the most important risk facing nuclear and coal power plant projects, due to social and local acceptance issues as well as complexity and uncertainty of siting and permitting. Furthermore, nuclear projects face high risks of cost overruns due to the limited recent construction experience (which may diminish over time), while coal-fired power projects face the risks of stringent environmental regulation and climate polices. The regulatory risk of investments in gas-fired generation may be low, but investors in this technology in countries heavily dependent on gas imports face the relatively high risks associated with gas supply and price increases which can potentially affect significantly gas-fired generation costs. Nuclear, on the other hand, benefits from stable costs once operating, and a much more secure fuel supply. Renewable projects, perhaps generally less subject to environmental scrutiny, face nevertheless the risks associated with transmission, including access, interconnection, and integration – all of which do have an impact on costs, although again, like nuclear, benefit from low and stable operating costs.

Like the LCOE, there are other methods that are, based on the general discounted cash flow (DCF) methodology but which may address additional risk sources in the calculation and analysis of the net present values of alternative projects, taking into account capital at risk, the proportion of debt-equity financing, taxation, etc. The NPV method calculates the net present value of all cash flows in a project, including revenues, with the same types of assumptions as those made in the levelised lifetime-cost approach. The difference is that NPV focuses directly on the profitability of a project instead of only its cost, thereby introducing electricity price into the equation. The NPV method allows for simulations in which multiple uncertainties and risk factors are taken into account. The assumptions about the possible and expected outcomes of the various cost factors will determine the possible and expected outcomes of NPV calculations. Monte Carlo simulation using probabilistic distribution can be used to provide additional insights to investors and industry planners about the impact of technical, operational, and price risk, as compared to the levelised cost methodology.

B. Generation versus power system costs

The major cost elements of a power system include generation, transmission and distribution. As a general rule of thumb, generation costs typically account for between 60% and two-thirds of the total electricity bill of a power system. The other one-third to 40% are composed of transmission, distribution and marketing costs. These costs outside generation costs are important cost components that are beyond the scope of the LCOE methodology.

While all generation technologies incur certain grid integration costs, the integration of variable renewable-based electricity production such as wind and solar is expected to be more costly than non variable resources due to the need to increase flexibility in the system. Wind power can only be generated when wind speeds are within an operational range. Thus, back-up resources are generally required to maintain reliable supply in periods when wind speeds are outside of that range. This has implications for operating and balancing the system in real-time, as well as for total system costs and the long-term development of the generation portfolio and networks (see Chapter 8).

The LCOE results also do not reflect the locational dimension of the investment. From a systemic perspective, a wind farm located close to load centres that can be connected to the distribution system at low voltage is more advantageous than a wind farm of the same capacity that is remotely located and needs a costly new transmission line to get it connected to the system. Network costs are expected to rise with the increase in wind power. Large concentrations of wind power require large transmission capacities to distribute wind power production across larger areas when it is windy – and to import electricity from alternative sources when wind resources are insufficient. Building this transmission capacity in the right place, time frame and capacity (as wind power capacity expands) is a major regulatory and investment issue. Hydro power with reservoirs is particularly useful as a balancing tool and back-up for wind power. If hydro and wind are not in the same area, it may be cost effective to connect them with transmission lines, even if this is initially expensive. Elsewhere, gas-fired capacity has filled this role, for example in Spain.

Comparative assessments of various alternative technologies based on the LCOE methodology could therefore be significantly enriched if they are complemented with proper consideration of the network, integration and balancing costs associated with alternative generation technologies.

C. LCOE, energy security and environment sustainability

The global power sector faces the twin challenges of energy security and climate change. Electricity security depends importantly on reliable and secure supply of the fuels used in power generation. Fuel supplies can be subject to interruptions for a variety of reasons. Supply interruption can be caused by weather (e.g hurricanes), or related to infrastructure failure, especially if there are only one or two supply links. These risks seem most acute in gas supply where OECD countries are likely to see growing import needs. As with other generation sources, gas supply risks can be mitigated through stocks, but these are relatively expensive to maintain compared to coal or uranium, and can also be subject to infrastructure risks. Other measures, notably fuel switching and interruptible contracts can also be employed.

Given the variable nature of natural "fuels" such as wind, solar and hydro, variable renewable–based generation cannot provide reliable baseload electricity without proper back up resources. While nuclear generation can rely on relatively stable and secure uranium supply sources, gas-fired generation especially in Europe is subject to long term risks of gas supply.

Of course, diversification has always been an essential element to ensure long term electricity security. A diversified generation mix coupled with a geographical diversification of fuel sources and supply routes and vectors would mitigate the long term risks of supply disruption. Such diversification strategy is equally applicable at company, national or regional level. As has been noted earlier, since around 1990, gas has emerged as the most important incremental power source, and the trend has accelerated so that gas has supplied 80% of OECD incremental power needs this decade. Most generation capacity under construction in the OECD is gas-fired, and this trend is expected to continue at least into the medium term, especially if demand growth remains slow or unpredictable. It can be argued that gas is a flexible, low capital cost, low-risk option, an efficient way to meet peak and reliability needs, and an ideal complement for intermittent renewable generation. Many areas of the OECD, however, are likely to become increasingly dependent on gas imports over the coming decades, generally at greater cost and from more distant sources. Gas supply interruptions could impact power supply security, thus requiring a closer monitoring and coordination between the gas and power industries from a security of supply perspective.

Just as different energy sources play different and potentially complementary roles in ensuring security of supply, each generation technology also has unique impacts on the environment. Nuclear and renewable are considered part of the "low-carbon" technologies, while coal-fired power plants generally emit twice as much CO_2 as gas-fired power plants. These aspects related to energy security and the environment are beyond the scope of the LCOE methodology but must be taken into account in assessing various generation options.

Levelised costs are, thus, an important tool for policy makers in understanding the main cost drivers of an electricity system and in assessing the importance of policies for generation costs, for example the impact of carbon pricing on costs. Levelised costs may also provide some insight for investors in a first screening of generation options. Sensitivity analysis of individual cost factors, such as CO_2 and fuel costs, is relevant to investors and from a public policy viewpoint. However, a full analysis of a given investment project would complement the levelised costs with a more comprehensive risk analysis, in which multiple risks are taken into account.

9.2 Power market functioning and electricity pricing in competitive markets

In the traditional context of a vertically integrated monopoly, regulated electricity prices charged to consumers reflected the long-term average cost of producing electricity. The LCOE methodology resulted in an estimated constant real energy price that met all operating, fuel and financial costs. As such, the LCOE methodology provided a good basis for estimating the cost of electricity, which was normally allowed to be fully "passed through" to consumers in the traditional utility cost of service model.

In competitive generation markets, the relationship between average costs and prices is no longer obvious as prices are set by the marginal cost of the last dispatched technology (the one, in effect, with the highest marginal costs of all dispatched technologies). Average costs thus cannot be automatically recouped from consumers, and therefore asset owners and plant operators must bear the risk associated with the plant's output and the resulting revenue streams. Spot wholesale electricity prices fundamentally reflect dynamic electricity supply and demand conditions in a given market, where marginal pricing determines the market clearing price at each point in time. Markets in which the price of electricity actually sold is the only remuneration received by a power plant for its output are called "energy-only markets".[1]

Power systems are characterised by variable supply and demand and a lack of cost-efficient storage. With an increasing share of intermittent resources in the generation mix reflecting rapid deployment of wind and to a lesser extent solar power, supply is expected to be increasingly variable. Generation resources must be adequate and flexible enough to respond quickly to short-term fluctuations in both supply and demand. To ensure reliable supply, system operators require various types of reserves, as well as other so-called ancillary services. System operators normally contract these services from commercial players, often through competitive bidding. Payment for capacity reserves is part of the possible revenue stream to power generation assets. In actual system operation, generating resources must be available to respond instantaneously to changes in the system, requiring automatic regulation. For that purpose, system operators contract for so-called "automatic reserves". These reserves respond to a technical signal – frequency – rather than an economic price signal and are essentially traded in price per MW, rather than price per MWh.

1. Energy-only markets are referred to here as markets with no specific remuneration of available capacity (in addition to output).

Once a power plant is built, the investment is considered as "sunk costs". The competitiveness of a plant depends on its marginal cost, i.e., the cost of producing an additional unit of electricity, which is dispatched based on the economic merit order. Marginal costs mainly reflect the fuel costs. In many cases gas- or oil-fired turbines are the marginal plants that determine the spot price in competitive markets. In forward markets, the price is often set by CCGTs. This market clearing price is then used to pay all generators. This system provides an incentive for efficiency as the more efficient, lower-cost generator would earn a higher profit.

Investment in generation capacity earns a return during hours in which the price exceeds the marginal costs of a specific plant. Baseload plants tend to have low marginal costs and therefore will operate in as many hours as possible. They would earn a return on investment during those hours in which marginal costs of mid-merit and peak-load plants determine the price. In turn, mid-merit plants earn a return on invested capital during peak-load hours.

Peak-load plants provide the necessary power to meet demand in the few hours in which demand is at its maximum. Prices typically surge during peak hours, yielding a return to peak power. During peak hours, the price is set by the generator with the last available peak-load resource, who can bid this resource into the market at any price – as long as there is no price cap and competition from alternatives.

Several important factors influence the real-time operation of a specific power plant and the system to which it belongs. Depending on the circumstances, these factors may add value to a project or imply additional costs. The most important factors are operational flexibility, reliability and size of the plant.

Power resources need to be adequate and flexible enough to respond to fluctuations in both supply and demand. Electricity consumption varies over time with daily and seasonal peaks and, in some jurisdictions, demand is increasingly more "peaky" due to air conditioning load (e.g. Spain or Australia). Power plants also have to be occasionally taken offline for maintenance, repair, refurbishment or refuelling (in the case of nuclear plants). Finally, plant failures do occur from time to time unexpectedly causing temporarily forced shutdowns. Since cost-efficient electricity storage is limited, power systems need access to resources that can respond quickly to supply and demand fluctuations.

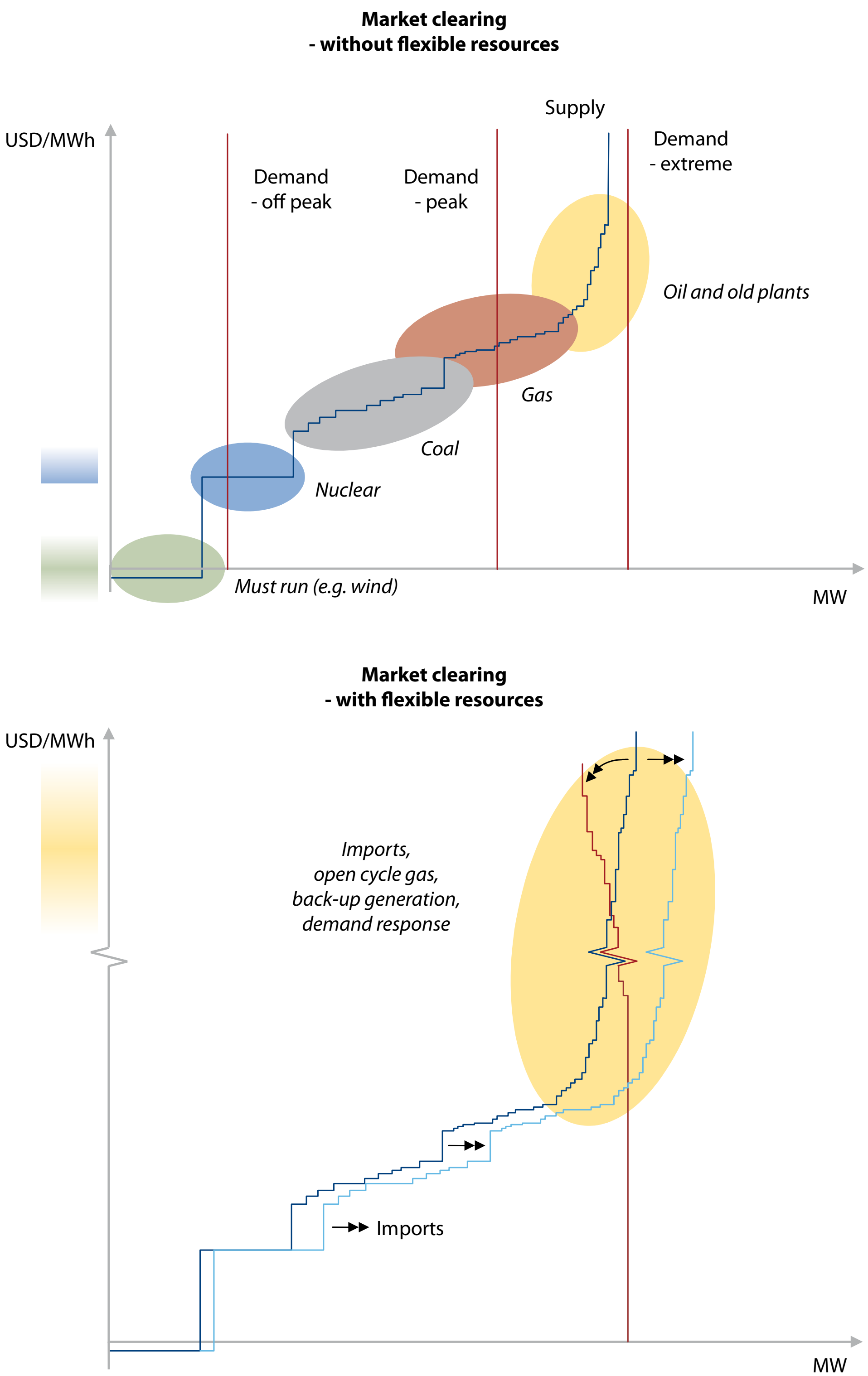
But maintaining flexibility may be costly. Plant units kept "spinning" as reserves will supply the grid for fewer hours and need high prices during peak hours to recover the invested capital. Price caps may thus create problems for remunerating investments in peak capacity (the "missing money" problem). Hydro power, older coal and oil-fired units, and CCGTs are particularly well suited for providing these adequately "back-up" services. Nuclear and wind power are particularly unsuitable.

The *N-1* criterion is a reliability standard often used in industry to ensure that the system has sufficient reserves to cope with the loss of any single generation or transmission unit. The need for reserves thus increases with the size of the largest unit in the system. As long as most conventional units were about the same size (400 to 600 MW) application of the N-1 criterion may not present a big issue. Since nuclear units are significantly larger (up to 1 600 MW) this criterion may add costs to the system that may be indirectly attributable to a specific project. On the other hand, small distributed generation units potentially reduce system vulnerability in case of failure of a single unit.

When demand increases, more plants need to operate and more expensive plants set the market price. When the price of coal or gas drops, the price of electricity can thus be expected to fall as well. More particularly, the relationship between gas and electricity prices is now well established and can be observed in many markets providing a natural "hedge" between fluctuating gas prices and market based electricity revenues. When something unexpected happens in real-time system operation, the price varies rapidly depending on the nature of the incident.

Figure 9.1 illustrates the principles underlying the market-clearing process and the critical impact that flexible resources may have, particularly during times of supply tightness.

Figure 9.1: Illustrative electricity market clearing based on marginal costs



Additional generation capacity is not the only source of flexibility. Improved cross-border trade allows for better sharing of resources across larger areas. Cross-border trade contributes to increased system flexibility if interconnections are adequate. Consumer participation contributes to flexibility by shifting demand to less critical (off-peak) periods. Demand response has the potential to become a critical resource in situations of scarcity. In times of supply tightness, even a very small degree of price elasticity can be enough to deliver the critical resources to balance the system, particularly if prices are allowed to spike. Additionally, less traditional resources, such as back-up power and distributed generation, are viewed as having new roles in adding value. These technologies can contribute to operational reserves and other ancillary services.

Flexible resources from imports and demand response may be critical in extreme demand situations. The upper half of Figure 9.1 illustrates the principles of market clearing in a system that does not account for flexible resources. Market-clearing prices are determined by the marginal plant at which demand intercepts the supply curve. Some plants, such as wind and CHP, are must-run and will be bid into the market at zero or even negative prices. Hydro power, which is not depicted in the graph, will not enter the merit order according to its marginal costs, which are negligible, but rather according to the expected opportunity cost at any given moment. This is especially important when the hydro resource is water-constrained. Nuclear has the lowest marginal costs of all the dispatchable power generation sources. Coal is often next. Gas-fired plants set the marginal price in most hours. In a few peak hours, the available resources with the highest marginal costs in the system must be used, often at very short notice. These might be oil- or gas turbines and, occasionally, other older plants that were built to operate as baseload but have now been shifted to the end of the merit-order stack to the extent that they can be mobilised quickly.

The lower part of Figure 9.1 shows that demand response resources and other flexible resources can considerably reduce the market-clearing price, making markets work more efficiently.

Coal, nuclear and hydro plants have historically had dominant positions in generation portfolios, typically as baseload technologies. They usually come in large sizes – benefitting from large economies of scale – and probably create sharper investment cycles. The low demand growth that is being observed in many OECD economies and that is likely to continue in the medium term, further increases the risk of building a new large baseload plant. Competition, cross-border trade and the emergence of CCGTs have changed this pattern. Trade across borders also tends to smooth investment cycles. In many countries, generation portfolios now also include CCGTs, wind power and other forms of distributed technologies. With their smaller sizes, lower investment costs and lower sensitivity to capacity factors (with the exception of wind power), these technologies are less risky at the margin and also contribute to a smoother investment cycle.

Hydro plants have a key advantage of "load following", i.e. many of them can be mobilised within the minute-by-minute time frame required by real-time balancing. Most other plants (conventional thermal power, coal-fired and gas-fired) require some time to start up or warm up, which often takes four to eight hours. Such plants can only be available for real-time balancing to the extent that they are partly, but not fully, dispatched. There is a real risk that a plant kept spinning for real-time balancing will not be called on even if it is available. This adds a risk premium – an opportunity cost – to the bids in the real-time market. Overall, the costs for reserving capacity in advance are expected to be lower than the average risk premiums commercial market players will charge when bidding the last resources into the real-time market.

9.3 Qualitative assessment of major risks associated with generation technologies

Generation costs are important factors in the choice of technology to meet increasing demand and to replace ageing plants. The LCOE methodology provides a framework for analysing such costs and for comparing the costs of various generation technologies. It provides a mine of insightful information within the parameters of a power plant, and on the impact of variations in individual cost factors. However in reality, the investment decision in power generation capacity is a much more complex process that involves taking into account the various cost uncertainties and non-cost factors.

Commercial market players evaluating investment opportunities in power plants face risks from many sources that cannot be captured in an LCOE analysis. Table 9.2 identifies the main risk factors, and provides a qualitative assessment of the levels of risk these factors entail.

Table 9.2: Qualitative assessment of generating technology risks

Technology	Unit size	Lead time	Capital cost/kW	Operating cost	Fuel cost	CO_2 emissions	Regulatory risk
CCGT	Medium	Short	Low	Low	High	Medium	Low
Coal	Large	Long	High	Low	Medium	High	High
Nuclear	Very large	Long	High	Medium	Low	Nil	High
Hydro	Very large	Long	Very high	Very low	Nil	Nil	High
Wind	Small	Short	High	Medium	Nil	Nil	Medium

Note: CO_2 emissions refer to emissions during combustion/reformation only.

All investment projects face at varying degree risks and uncertainties that investors need to manage. Investors generally use the best knowledge and available information to assess the likely range of financial outcomes of their proposed project by evaluating different scenarios. They may also undertake a stochastic analysis in which probabilistic values of uncertain variables are used in successive runs of a cash-flow model. This makes it possible to calculate an "expected value" (weighted average value of all scenarios) of the financial viability of the project.

Investors will then use this value to assess whether the expected financial return from a project meets their investment criteria. In practice, investors will consider the likelihood of a range of financial outcomes, as these provide an indication of the financial implications of the project. Companies will also take into account strategic considerations such as how the project fits within the company's overall asset portfolio, how it affects their corporate risk profile and their competitive position in a given market.

Faced with uncertainties, and particularly given very weak demand, a possible response from potential investors is to defer the investment decision in order to gain additional information accruing through time, thus reducing uncertainty and risk. If companies include this "option value of waiting", they may ultimately realise a greater value from their project because they can incorporate the additional information in the investment decision. On the other hand, if the expected project value is high enough to outweigh the option value of waiting, investors would invest immediately despite the future uncertainty. The additional project value required to trigger immediate investment is in fact a risk premium on top and above a normal rate of return.

One can reasonably argue that real option value provides a plausible explanation why most investments in new generation capacity in OECD countries have been in favour of gas-fired generation in the last fifteen years, even though the levelised costs of gas-fired generation are generally higher than nuclear and coal. The low option value of CCGTs resulting from relatively low capital costs, short construction times, high modularity and low emission compared to coal is expected to drive the continued investment in this technology, unless climate policy uncertainties can be significantly reduced through clear, stable and long term energy and climate policies.

Uncertainties have a cost to both investors and consumers. For example, environmental policy is a major area of uncertainty as policy instruments are still far from settled. Uncertainties and the resulting risks will eventually be reflected in the investment costs and in the cost of electricity. Risk premiums are likely to be recouped through a higher power price. The greater the level of uncertainty and risk, the greater this increase in power prices is likely to be. A recent IEA study on uncertainty estimated that power prices would have to rise by between 5-8% to overcome the risks associated with uncertainty on climate change policy (IEA, 2007b). The study also found that extending a CO_2 emission reduction period from 5 to 10 years can reduce risk premiums with between 4% and 40% depending on the technology.

Market uncertainties will eventually affect the capacity utilisation of a plant and, consequently, the average costs of producing electricity, as well as the financial performance and profitability of an investment. Capacity utilisation rates over the life of the project will be affected by market conditions. For example, nuclear and coal-fired power plants are suitable for baseload supply and are expected to achieve high capacity utilisation over the operating life, but if the total amount of installed baseload capacity is higher than minimum domestic and export demand, some baseload capacity is forced out of the market during some off-peak periods. This is a risk for power systems with a high share of baseload capacity or where demand for baseload is lost through, for example, industrial restructuring. A combination of concerns about market risk and a sensitivity to capacity factors tend to act in favour of CCGTs as the logical choice to supply mid-merit load. This is another consideration that might help understand the choice of CCGTs as a preferred technology for power plant investments in OECD countries.

Markets incorporate these uncertainties and risks in institutional assessments of the cost of capital. The risk level also subsequently determines the ratio of debt versus equity financing, as well as the required rate of return on both debt and equity. For relatively low-risk projects it may be possible to finance a larger share of the capital requirements with debt and at lower rates. The riskier the project, the higher return on equity investors would require.

The cost stability of some technologies, notably nuclear, may also be attractive to certain classes of investors and power buyers concerned, for instance, with ensuring a long term stable cost of power to preserve and enhance competitiveness of industrial production.

Thus the decision to invest in a specific technology depends on a number of factors. Cost competitiveness is one, but there are non-cost factors that in some cases may be more important than cost considerations. Uncertainties, risks and their management are probably the biggest challenges to investors. More particularly, policy uncertainties may act as barriers to investment in generation. Long-term policy commitments instead reduce the investment risks and foster a healthier investment climate.

Ultimately, investments are made in a relatively uncertain market place and they must thus reflect the expected value of a project, the risk profile of the investor and the latter's financial resources. In short, they must fit within the corporate strategy of investors.

9.4 Policy considerations

The OECD power sector hosts tremendous opportunities for power plant investments over the coming decades. These investments are expected to result in a gradually greener and cleaner generation mix which, ultimately, will be mostly decarbonised. The investment challenges are not insurmountable. Innovation, technology and collective efforts are, however, needed to ensure that these investments converge towards addressing the twin challenges of energy security and environmental sustainability. There is a role for industry and governments to ensure that investments that are being made today contribute towards the pursuit of policy goals.

Ensuring electricity security requires timely, diverse, adequate, correctly sized and placed investments in all segments of the value chain. The reality is that there are major barriers to investment, including policy and market uncertainties. In the currently weak macro-economic environment, with low and uncertain energy demand growth, generating technologies with high capital cost and long lead times such as nuclear facilities may struggle. Low public acceptance for some generating technologies (e.g. coal without CCS) and power transmission projects coupled with complex, lengthy and costly siting and permitting processes are another persistent feature of power sector investment. This again works against highly capital-intensive and risky projects. Furthermore, uncertainty in climate policy and, perhaps more importantly, its timing presumably have a detrimental effect on investment. Some governments have taken the initiative to offer incentives (e.g. feed-in tariffs for renewable energy in Germany or Spain, loan guarantees for new nuclear power plants in the United States) to support the development of certain technologies, but depending on their objectives might need to take still stronger actions.

A key goal of climate change policy is to drive investment in power generation towards technologies that emit less greenhouse gases. The strong deployment of renewables in recent years goes in the right direction in that regard. Larger scale of wind power development will however need more investment in transmission and in smart grids to make power system more flexible. Without clear policy guidance, there is a risk that investment decisions will be deferred completely, especially for high risk projects, eventually jeopardising system reliability.

Markets would benefit from more stable, transparent and long-term indications regarding the future framework for climate change abatement. Market-based instruments such as the European Union Emission Trading Scheme (EU ETS) have been implemented in OECD countries to drive investments towards cleaner generation. Putting a price on CO_2 emissions would translate a policy goal (i.e. a given emission reduction) into a quantifiable cost factor that investors can take into account in investment decision making. The cost of emission allowances would put upward pressure on fossil-fuelled generation costs, providing an incentive to shift away from carbon-emitting generation sources.

A key challenge for investors is the choice of technology, which ultimately has important implications for the environment and for security of supply. Levelised costs of electricity generation can guide the selection of cost effective technologies and provide estimates of the levels of investments that would be required to meet consumer needs. Investors respond to market needs by investing in the kind of technologies that make the strongest business case.

Levelised costs of coal, gas, nuclear, and wind generation units are all within a competitive range that makes them worthy of consideration in a diversified generation portfolio. CCGTs are generally considered as a technology offering the highest flexibility and the lowest risk, even when considering their exposure to potential increases in gas prices. Nuclear and hydro power standout as proven low-CO_2 emitting technologies which can produce baseload electricity at competitive prices. Apart from hydro power, for which few further sites are available in most OECD countries, coal plants generally have low levelised costs under most circumstances except when there is a significant price on CO_2. Advancements on carbon capture and storage technologies are necessary to maintain competitiveness of coal in a carbon-constrained power sector.

Since investors normally do not incorporate the costs of externalities in investment decision making, government intervention would be necessary to “internalise the external costs” of the environmental damages resulting from power generation. Thus, governments are best positioned to assess, on a broad scale, the social and environmental costs and benefits associated with power generation, as well as the energy security aspects of, for example, a high dependence on natural gas imports destined to the power sector.

Some technologies, such as renewables and nuclear, once the plants are built, provide benefits in terms of price stability, which is also not captured by the LCOE methodology. Other technologies such as coal and, in particular, gas are instead subject to fuel price volatility, and therefore contribute to the risks of electricity price volatility. The flexibility value of some technologies, such as gas with short lead time or hydroelectricity with storage in the context of large deployment of renewable and/or increasingly peaky power demand, is also not captured in LCOE analysis. Furthermore, depending on the structure of the economy, some technologies may make a greater contribution to employment and GDP growth than others. *A priori,* it is difficult to tell which technology would have the greatest macroeconomic value, which depends partly on the industrial structure of a given national or regional economy.

Markets should be supported by appropriate government actions so that investments balance efficiency, diversity, scarcity, reliability and environmental responsibility, and this, not only in terms of the quantity but also the quality of investment. The main collective goal is to ensure that sufficient and timely investments are made at the right locations and using clean generation technologies. Governments can play a strategic, pro-active role by providing strong incentives for investors, essentially creating market-based signals to minimise the risks of under-investment, and by guiding the markets with clear, transparent, coherent and stable energy and climate policies.

As a facilitator of well-functioning markets, governments thus play a crucial role as economies move towards a carbon-constrained world. Since not all private investment decisions are equally supportive of such policy goals, governments should aim to foster the right technology and generation investment choices through regulation, policies and measures designed to achieve such policy goals.

New generation capacity is an important element of meeting increasing energy demand, but it is not the only option. Incremental electricity needs can also be met through a mix of sources including new generation units, improved energy efficiency in end-use as well as in generation and transmission, improved interconnections and imports. Investments in transmission systems and better integration of demand participation are thus important alternatives to new generation resources. All alternatives need to be evaluated to ensure the best options are pursued.

In summary, this report focuses on the levelised costs and the sensitivity analysis of various technology options for power generation in 2015. Such cost estimates are essential to power plant investment decisions and as such, provide insightful information to the market place. However, given the uncertainties and risks involved, other factors must also be carefully evaluated in the context of real-life investment decisions. Levelised costs are also useful to policy makers as discussed previously, but they need to be complemented by other forms of analysis to ensure balanced policy making.

References

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IEA (2007b), *Climate Policy Uncertainty and Investment Risk,* OECD, Paris, France.

Carbon capture and storage

10.1 Introduction

There is an increasingly urgent need to mitigate greenhouse gas (GHG) emissions, including those related to the production and consumption of energy, to avoid the severe consequences caused by climate change. The IEA *Energy Technology Perspectives* (ETP) study of 2008 projects that without efforts to combat climate change global CO_2 emissions will rise by 130% between 2005 and 2050 (IEA, 2008a). Avoiding this development requires an energy revolution: improvements in energy efficiency, greater usage of renewable energy and nuclear power as well as the decarbonisation of fossil fuel usage. To achieve this, power generation has to be virtually decarbonised. The only technology available to mitigate GHG emissions from large-scale fossil fuel usage is CO_2 capture and storage (CCS). The ETP BLUE scenario, which aims at reducing global GHG by 50% by 2050, demonstrates that CCS will need to contribute nearly one-fifth of the necessary emissions reductions to reach this target at a reasonable cost. In power generation, one quarter of the necessary CO_2 reduction is attributable to CCS. This highlights the important role CCS in power generation may play to realise substantial CO_2 reductions.

Despite the potential of CCS in the longer term, by 2015, the base year of the cost analysis of *Projected Costs of Generating Electricity,* CCS in power generation is generally not expected to play a major role, although demonstration and deployment projects have to be brought online in this time period to advance the development and uptake of CCS in the long run. Hence, CCS may become commercially available over the lifetime of power plants being build today and has to be taken into consideration in investment decisions made in the near term, either on a plant level by allowing later retrofit of CCS or on a strategic level as a power plant with CCS may become a competing generation option over the lifetime of a plant being invested in today.

Therefore the following provides an overview of CCS, starting with an outline of the prospects of CCS based on a scenario analysis with the IEA *Energy Technology Perspectives* (ETP) model, an overview of the technology options, their costs and research and development (R&D) challenges for capturing CO_2 in power generation and subsequent transport and storage.

10.2 Role of CCS in CO_2 mitigation

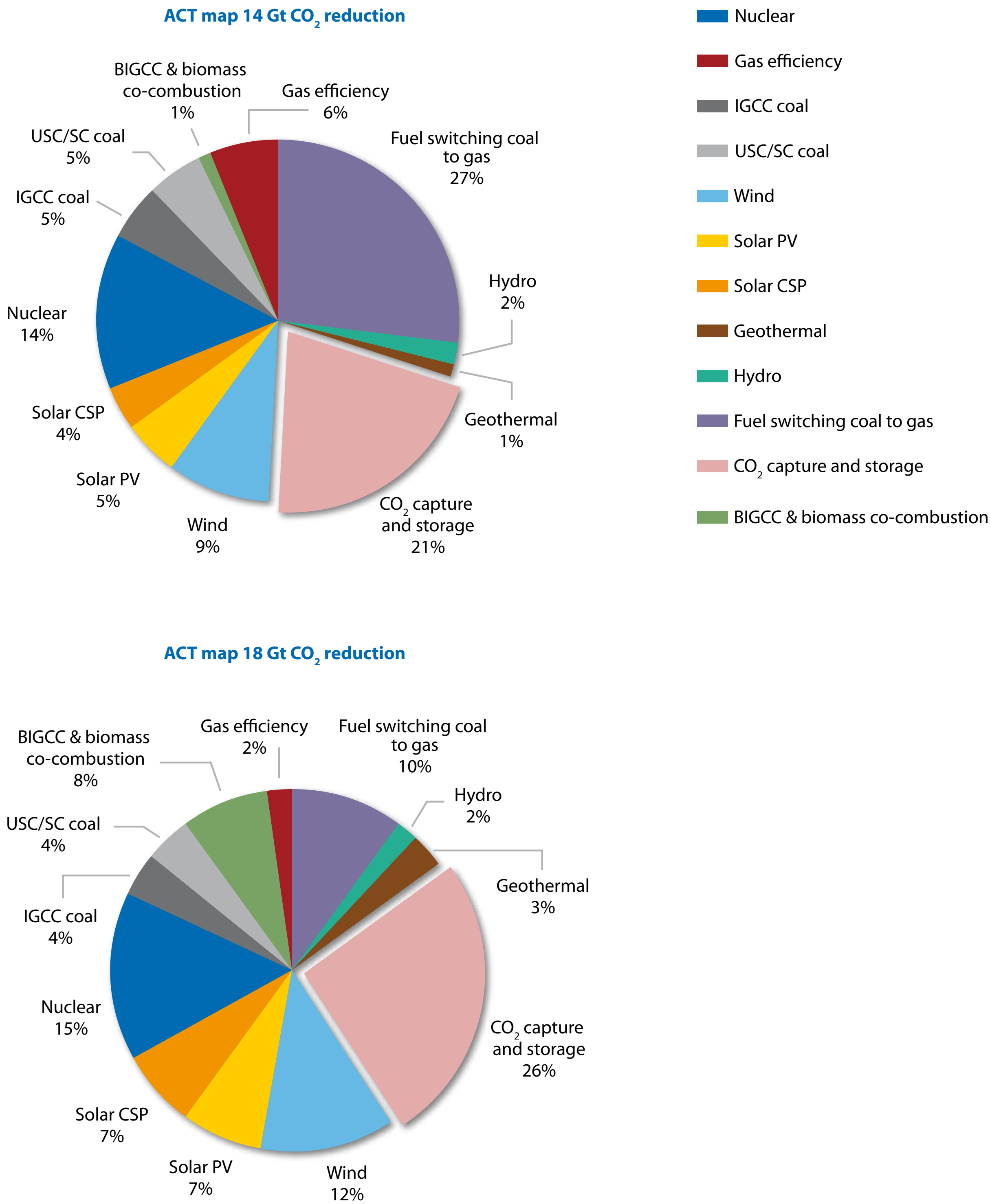
The role CCS could play to achieve substantial GHG reductions has been assessed in a scenario analysis within the IEA study *CO_2 capture and storage: A key abatement option* (IEA, 2008b). While the BASE scenario presented there reflects developments that are expected on the basis of the energy and climate policies that have been implemented and are planned to date, two sets of scenarios explore the implications from stabilising global CO_2 emissions in 2050 to 2005 levels (ACT scenarios) and from halving CO_2 emissions by 2050 (BLUE scenarios). To foster CO_2 mitigation in the ACT scenarios, a CO_2 incentive of 50 USD per tonne of CO_2 has been assumed making measures and policies up to that mitigation cost level cost-competitive. In the BLUE scenarios, the CO_2 incentive has been increased to USD 200/t CO_2. Each of the two scenario sets consists of a Map scenario with relatively optimistic assumptions regarding future technology characterisations and of variants analysing the future availability and characteristics of technologies [High nuclear (hiNUC): 2000 GW instead of 1 250 GW nuclear capacity worldwide, no CCS: no carbon capture and storage available; Low renewables (loREN): lower cost reductions for renewable power generation technologies assumed; Low end-use efficiency gains (loEFF): assuming a 0.3% lower annual energy efficiency improvement compared to the BLUE Map scenario].

A core result of the scenario analysis is that not a single technology, but a portfolio of technologies is needed to achieve the CO_2 reductions envisaged in the scenarios. CCS in power generation is one important option among other mitigation measures such as CCS in the industry and upstream sectors, energy efficiency improvements, higher use of renewable energy carriers and nuclear power.

Power generation in the BASE scenario grows by 179% between 2005 and 2050. Coal- and gas-based electricity generation accounts for three quarters of power generation in 2050 compared to two-thirds in 2005. Global energy-related CO_2 emissions rise from 27 Gt CO_2 in 2005 to 62 Gt in 2050. The share attributable to electricity generation increases thereby only slightly from 41% to 44% despite the higher share of fossil fuels in power generation, since the efficiency of fossil power generation improves over time, so that the CO_2 intensity of electricity generation in 2050 is slightly below that in 2005.

In the ACT Map scenario emissions in power generation are reduced by 14 Gt compared to the BASE scenario in 2050. CCS accounts for one fifth or nearly 3 Gt of this reduction in 2050 (Figure 10.1). In the BLUE scenario the contribution of CCS to mitigate CO_2 increases further in relative (26%) and absolute terms (4.7 Gt).

Figure 10.1: Reduction in CO_2 emissions from the baseline scenario in the power sector in the ACT Map and BLUE Map scenarios in 2050, by technology area



Source: IEA, 2008b.

Most electricity generated by coal-fired power plants in the ACT Map and BLUE Map scenarios, and half of the gas-fired power generation in the BLUE Map scenario, comes from plants equipped with CCS. Retrofitting of coal plants with CCS plays a significant role in the ACT Map scenario; and at the price of USD 200/t CO_2 assumed in the BLUE Map scenario, there is sufficient economic incentive to accelerate the replacement of inefficient power plants before they reach the end of their life span.

The growth of CCS in the BLUE Map scenario compared to the ACT Map scenario is largely attributable to installing CCS at gas and biomass plants. As biomass contains carbon captured from the atmosphere, the capture and storage of that carbon results in a net removal of CO_2 from the atmosphere. This can offset emissions elsewhere. However, this option is costly: biomass transportation costs limit plant size, whereas CCS benefits from economies of scale.

Table 10.1 shows the electricity generation mix for the different ACT and BLUE scenarios in 2050. Under less optimistic assumptions regarding renewable technologies (loREN) and lower efficiency improvements (loEFF), CCS gains a higher share in power generation compared to the MAP scenario. A higher nuclear generation (hiNUC) only partially substitutes the generation from plants with CCS, instead also renewable generation gets replaced and the overall electricity supply increases to substitute fossil fuels in the end-use sectors. The only BLUE scenario that leads to significantly higher CO_2 emissions is the scenario without CCS being available. In this scenario CO_2 emissions exceed the one of the BLUE MAP scenario by more than 40%. To reach again the same reduction target in the BLUE noCCS scenario as in the MAP scenario, the CO_2 incentive would have to be nearly doubled from USD 200/t CO_2 to USD 394/t CO_2. This illustrates the significant role of CCS may play in realising climate objectives.

Table 10.1: Electricity generation mix in 2050 for the BASE scenario and different variants of the BLUE scenario

Electricity generation (TWh/yr)	2005	Baseline	Blue map	2050 Blue noCCS	Blue hiNUC	Blue loREN	Blue loEFF
Nuclear	2 771	3 884	9 857	9 857	15 877	9 857	9 857
Oil	1 186	1 572	133	123	150	210	332
Coal	7 334	25 825	0	353	0	0	0
Coal + CCS	0	3	5 468	0	4 208	7 392	7 461
Gas	3 585	10 557	1 751	4 260	1 570	1 747	2 073
Gas + CCS	0	83	5 458	0	4 926	6 711	6 820
Hydro	2 922	4 590	5 260	5 504	5 203	5 114	5 385
Bio/waste	231	1 682	1 617	3 918	1 606	1 448	1 689
Bio + CCS	0	0	835	0	678	1 103	1 077
Geothermal	52	348	1 059	1 059	1 059	1 059	1 059
Wind	111	1 208	5 174	6 743	4 402	3 988	5 951
Tidal	1	10	413	2 389	419	165	806
Solar	3	167	4 754	5 297	4 220	2 314	4 987
Hydrogen	0	4	559	517	472	664	649
Total	**18 196**	**49 933**	**42 338**	**40 020**	**44 790**	**41 772**	**48 146**
CO_2 in 2050 (Gt CO_2/yr)	27	62	14	20.4	13.4	14.2	15
Marginal cost to meet target (USD/t CO_2)			200	394	182	206	230

Source: IEA, 2008b.

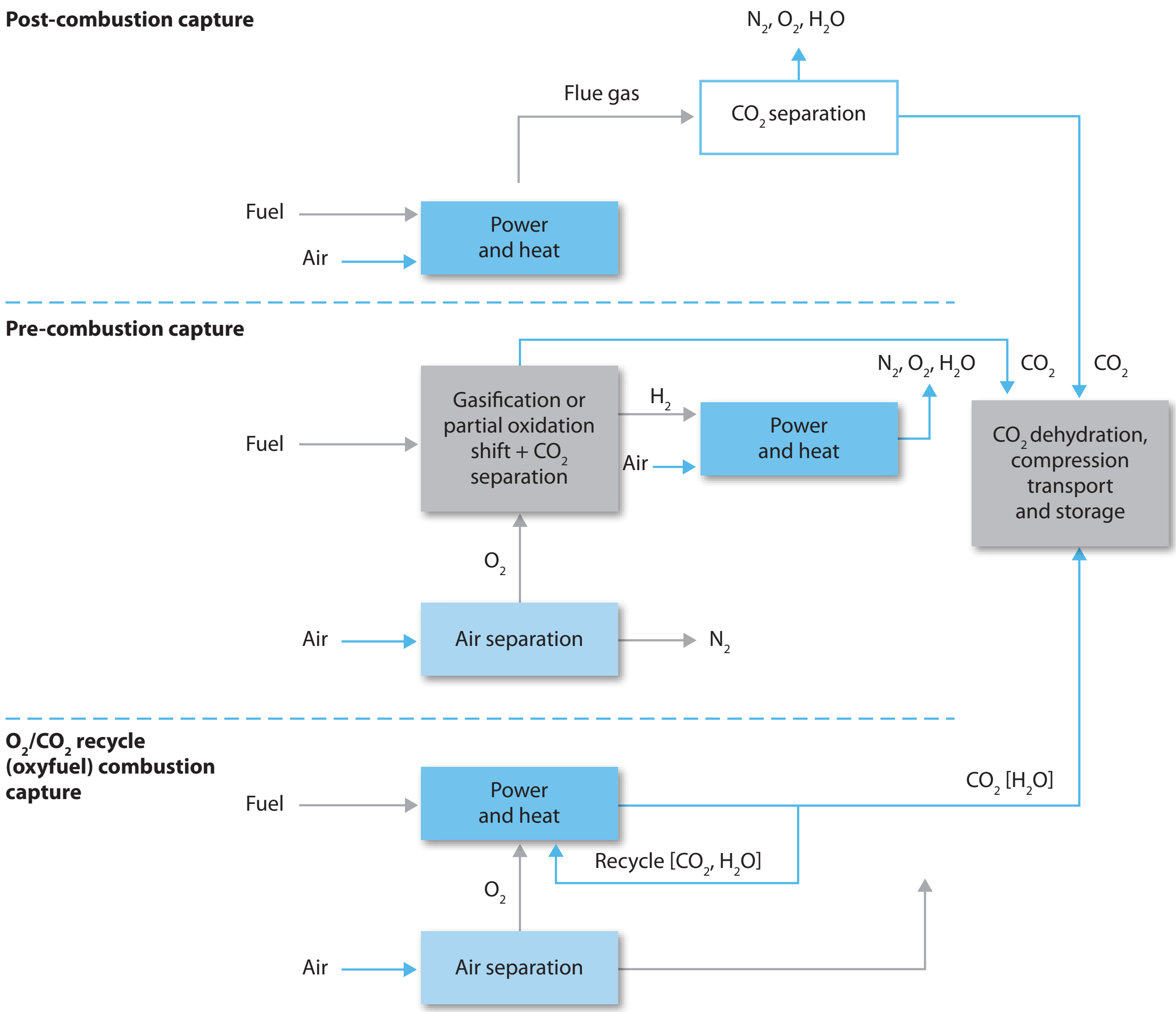
10.3 CO_2 capture and storage in power generation

There are three main technology options for CO_2 capture: post-combustion capture through capturing CO_2 from the flue gas, pre-combustion capture by separating the carbon from the fuel before burning it, and oxy-combustion under an oxygen atmosphere resulting in a flue gas stream mainly consisting of CO_2 for final storage (Figure 10.2).

Capture methods in power generation

In the post-combustion process, CO_2 is captured from flue gases that contain 4% to 8% of CO_2 by volume for natural gas-fired power plants, and 12% to 15% by volume for coal-fired power plants. The basic technology for separating the CO_2 from the flue gas uses a chemical absorption process (with amine-based solvents such as MonoEthanolAmine) and has been applied in industry on a commercial scale for decades. The challenge, however, is to recover the CO_2 from the solvent with a minimum energy penalty and at an acceptable cost. The heat requirement for the regeneration of the solvent varies between 4.4 MJ/kg CO_2 and 3.2 MJ/kg CO_2 for one of the latest chemical absorption systems (Feron, 2006; Peeters *et al.*, 2007).

Figure 10.2: CO_2 capture processes



Sources: IEA, 2008b based on IPCC, 2005.

The lower value corresponds to a coal power plant, whereas gas-fired power plants require a higher specific regeneration energy because of the lower CO_2 concentration in the flue gas. For coal power plants, the solvent regeneration yields an efficiency loss of around 6% points. Taking into account the electricity needs for compressing the CO_2 to a pressure of 110 bar (for pipeline transport) and for auxiliary equipment, such as flue gas fans and solvent pumps, the overall efficiency loss increases to 10%.

Research for improvements of the post-combustion technology focuses on reducing the efficiency loss caused by the CO_2 separation from the flue gas. Alternative solvents as chilled ammonia, ionic liquids, sodium carbonate solutions or amino-acid salts as well as other separation methods such as membranes are being studied. Achieving for example a reduction of the regeneration energy needed for the solvent from 3.2 GJ/t CO_2 to 2 GJ/t CO_2 would reduce the overall efficiency loss of the coal capture plant from 10% to 8% (Feron, 2006). For amine solutions, an increased solvent concentration reduces the energy need for regenerating. At the same time, however, it increases the corrosiveness of the solvent affecting the economic performance of the plant through reduced availability or shorter equipment lifetime. Improving inhibitors against degradation and corrosion of the solvent is therefore a further research area.

Pre-combustion capture processes separate the CO_2 from the fuel before burning it. The process can be used for a variety of fuels. In the case of a liquid or solid fuel, it has first to be gasified, before it is reacted with oxygen and/or steam and then further processed in a shift reactor to produce a syngas consisting of hydrogen and CO_2. The CO_2 is captured from a high-pressure gas mixture (up to 70 bars) that contains between 15% and 40% CO_2. The hydrogen is used to generate electricity and heat in a combined-cycle gas turbine. Beside electricity generation, the hydrogen can serve as input for fuel cells, in the production of other fuels or as feedstock in industry. Due to comparatively high concentration of the CO_2 in the syngas, a physical absorption process for CO_2 separation can be used, in which a solvent absorbs the CO_2 at high pressure and releases it again at lower pressure. The energy requirement for the regeneration of the solvent is roughly half that of a chemical absorption process (Gibbins and Chalmers, 2008). But efficiency penalties are associated with the energy used for the shift reaction and the oxygen generation as well as the necessary gasification in case of solid or liquid fuels. The overall efficiency loss of a pre-combustion capture plant for coal (integrated gasification combined-cycle, IGCC) is in the near term estimated to be between 8 and 10% compared to an IGCC plant without CO_2 capture (Damen, 2007).

Further research in material science for the gasifier is needed to make the construction materials more resistant against flowing slag and corrosive gases occurring at the operating temperatures from 1 350°C to 1 600°C. For the turbine, the higher heat transfer coefficients of hydrogen compared to natural gas or syngas require materials that can withstand temperatures in excess of 1 400°C. Another relevant research area represents the development of alternative air separation methods to reduce the efficiency loss associated with the presently used cryogenic method. Overall, the efficiency losses could be reduced by these improvements to 6% in the long-term (IEA-GHG, 2003).

The oxy-combustion process involves the removal of nitrogen from the air using an air separation unit (ASU) or, potentially in the future, membranes. The fossil fuel is then combusted with near-pure oxygen using recycled flue gas to control the combustion temperature. The flue gas consists mainly of CO_2 and water vapour with a CO_2 concentration between 70-85% depending on the burned fuel. In case of coal, nitrous and sulphur oxides as well as other pollutants can be present in the flue gas and must be removed before storing the CO_2. For a steam coal power plant, the oxygen generation using standard cryogenic air separation (99.5% purity) accounts for an efficiency loss of 7%, so that with the electricity needed for CO_2 compression the overall losses increase to around 10%. By reducing the purity of the oxygen to 95% and by further optimisation of the air separation process, the efficiency loss could be reduced to 8% in the future (Pfaff and Kather, 2009).

The research developments are focussing on reducing the energy requirement for the provision of oxygen. The use of ion-transport membranes (ITM) operating at 800°C to 900°C to produce oxygen from compressed air could be an alternative to the currently available cryogenic air separation. ITM is expected to reduce the energy consumption for oxygen production by 25-35% compared to a cryogenic air separation (Broek *et al.,* 2009). Chemical looping is a variant of oxy-combustion, in which the oxygen for the combustion is passed to a solid oxygen carrier in an air reactor. In the fuel reactor the oxygen from the oxygen carrier is reduced by burning the fuel. Since no direct contact between air and fuel occurs, a relatively pure CO_2 stream can be obtained from the flue gas after condensing the water vapour.

Retrofit/capture-ready plants

Global electricity demand is expected to continue to rise in the future. Many coal fired power plants are presently in the construction and planning phase, especially in non OECD countries. Due to the long lifetime of coal power plants and the absence of a sufficient incentive to invest in CCS today, most of the coal power plants being built over the next decade will not be equipped with CCS. If CO_2 mitigation becomes a priority, these plants might be candidates for retrofitting with CO_2. Given the efficiency penalty of CO_2 capture, such retrofit only makes sense for existing power plants with high efficiencies. For coal power plants, this means that the net electric efficiency has to be above 40% to make retrofit an economically viable option. This excludes 90% of the current existing capacity stock and implies that only recently build coal fired power plants are suitable for retrofit. Retrofitting gas power plants requires efficiencies of above 55% to make economic sense.

Two options are available for retrofitting existing conventional gas or coal power plants: post-combustion capture or oxy-combustion. In the case of retrofitting the plant with a post-combustion capture system, a scrubber for separating the CO_2 and a column for regenerating the solvent have to be installed. The retrofit of an oxy-combustion system requires an air separation unit for the oxygen production and a rebuild of the boiler to allow recirculation of CO_2 to control the boiler temperature. Both options need space available at the plant for the additional equipment. An IGCC plant can be retrofitted with a shift reactor and a scrubber to capture CO_2. In all cases the retrofit is accompanied with efficiency losses, so that the maximum power output declines.

The idea of later retrofitting a plant with a capture system might also be included in the planning phase of new plant, if the construction of a plant with CO_2 capture from the outset is not a viable alternative for economic or regulatory reasons. This concept is referred to as "capture-readiness" and includes the requirement of sufficient space and access for adding later the additional capture facilities as well as the identification of reasonable transport routes to a CO_2 storage site.

Transport and storage

The CO_2 has to be transported from the capture plants to the storage sites. It can be transported by pipelines, ships and road tankers. For large quantities of CO_2, a pipeline is the most cost-effective means of transportation. CO_2 pipelines are similar to natural gas pipelines, but are made of steel that is not corroded by CO_2. In addition, the CO_2 is dehydrated to reduce the likelihood of corrosion. The main design parameters for a pipeline affecting its flow rate and its costs are the diameter, the wall thickness and the pressure loss along the pipeline. The flow rate can be increased by a larger diameter or a higher pressure drop, i.e. increasing the ratio between input and output pressure. Larger diameter and thicker walls due to the higher input pressure increase, however, the steel demand for the pipeline, while a higher pressure drop requires more compressor stations as well as additional re-compression. Hence, the design of the pipeline has to be determined based on the actual transport situation through an optimisation process.

The cost of transporting CO_2 per unit of weight is much lower than for natural gas or hydrogen because it is transmitted in a liquid or supercritical state with a density 10 to 100 times higher than that of natural gas. Depending on the pipeline design, the estimated costs per tonne of transported CO_2 can vary from USD 2/t CO_2 to USD 6/t CO_2 over 100 km per year for a CO_2 quantity of 2 Mt, which corresponds roughly to the amount of CO_2 produced by a 400 MW coal plant in a year. Scale-effects reduce the costs for 10 Mt transported over the same distance to a range of USD 1/t CO_2 to USD 3/t CO_2.

Various options exist for storing the captured CO_2. CO_2 can be stored in deep saline aquifers, which are salt-water bearing sedimentary rocks. They can be found all over the world and seem to present the most promising option for storing CO_2 in the long-term. A comprehensive assessment of these geological structures is, however, necessary to understand better the storage potential. Estimates for the global storage potential vary between 2 000 to 20 000 Gt CO_2. The costs for storage in saline aquifers can go, depending on the geological conditions, from below USD 1/t CO_2 to USD 33/t CO_2 (IPCC, 2005).

CO_2 is already injected in oil fields to increase the recovery in the final stages of exploitation (CO_2 enhanced oil recovery, CO_2-EOR). CO_2 storage in the case of miscible EOR ranges from 2.4 to 3 tonnes CO_2 per tonne of oil produced. Oil production costs with EOR range from 7 to 14 USD/bbl. Assuming an oil price of USD 85/bbl and an injection rate of 2.5 t CO_2 per tonne of oil, the profit could amount up to USD 200-220/t CO_2, if CO_2 is provided without costs. To assess the CO_2-EOR potential accurately, a field-by-field assessment is necessary. Estimates for storage potentials vary widely, from a few Gt CO_2 to several hundred Gt CO_2.

CO_2 can also be injected in a depleted gas field to re-pressurise the field and to increase thus its productivity (CO_2 enhanced gas recovery, CO_2-EGR). The depleted gas field may still contain, depending on the geologic characteristics, 10-40% of the original gas in place. The economics of CO_2-EGR are, however, less favourable than CO_2-EOR, as the revenue per tonne of CO_2 injected is lower. About 0.03-0.05 tonnes of CH_4 are recovered for each tonne of CO_2 injected. Using a gas price of USD 10/GJ CH_4 and CO_2 storage costs of USD 10/t CO_2, CO_2-EGR can result in revenues of up to USD 6-17 per tonne of CO_2 injected, if CO_2 is provided for free. An initial screening of depleted gas fields for CO_2 injection (IEA-GHG, 2003) suggests a worldwide storage potential of 800 Gt in gas fields at a cost of USD 150/t CO_2 (more than 6 times the EOR cost). An alternative estimate for storage costs of USD 10/t CO_2, considers that the total CO_2 storage potential in gas fields is more than 150 Gt.

Unmineable coal seams are those coal deposits that are either too deep or too thin to warrant commercial exploitation. Most coal contains methane absorbed into its pores. The injection of CO_2 into deep unmineable coal seams can be used both to enhance the production of coal bed methane and to store CO_2 (enhanced coal-bed methane). Prerequisite is, however, that the coal has a suitable permeability. The global storage potential for enhanced coal-bed methane has been estimated to be around 150 to 230 Gt CO_2.

Further CO_2 storage options include salt caverns, ocean storage, mineral carbonation, limestone ponds, algal bio-sequestration and industrial use. Salt caverns offer very limited capacity compared to other geological options. Ocean storage is seen as controversial due to its unknown impact on marine life. For the North-East Atlantic region only, ocean storage has been prohibited in 2007 by the marine protection treaty OSPAR. Mineral carbonation is based on the reaction of ground magnesium or calcium silicate with CO_2 to form a solid carbonate. Due to the large material volumes[1] involved, it appears questionable whether mineralisation will present an opportunity for storing large amounts of CO_2. The concept of dissolving flue gas containing the CO_2 in ponds with water and dissolved limestone would require enormous ponds and is considered as highly speculative. The approach of fixing CO_2 in algae based on photosynthesis is under research. CO_2 is used today in many industrial sectors including food and beverages or horticulture. The volume of such usages (100 to 200 Mt CO_2 per year) is, however, small relative to the future storage requirements per year (several gigatonnes per year).

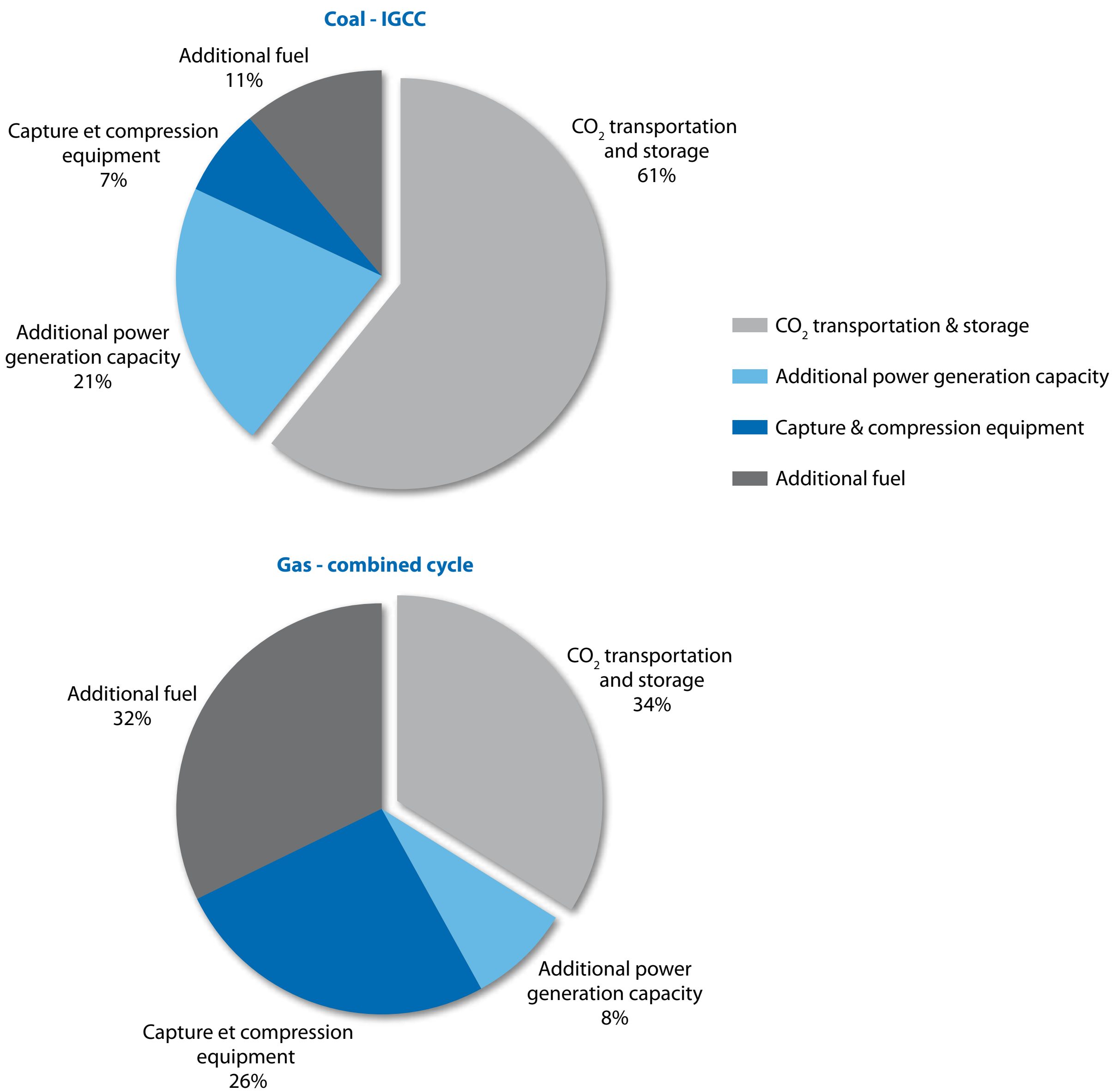
1. 1 tonne of CO_2 requires 1.6 to 4.7 tonnes of material and creates 2.6 to 5.7 tonnes of solid products.

Costs of capturing CO_2 in the power sector

The steps of CO_2 capturing, transporting and storing determine the overall costs of CO_2 capture and storage from a power plant.

The costs for capturing CO_2 at a power plant increases the overall plant costs for the additional equipment needed, the costs caused by the loss of electric efficiency requiring a larger gross capacity for the same net power output and the additional fuel costs caused also due to the lower overall efficiency. For an IGCC power plant with capture, the transport and storage costs can account for more than half of the overall capture costs as illustrated in Figure 10.3.[2]

Figure 10.3: Cost components of the capture costs for a coal and natural gas power plant



Source: IEA, 2008b.

2. This should put into perspective the figures for CC(S) reported in this study, which only include the costs of carbon capture but not the costs of transportation and storage.

The costs for the capture equipment and the additional power generation capacity affect the overall investment costs of the capture power plant. Table 10.2 shows the investment cost ranges for different types of power plants with and without capture. The data are based on (IEA, 2008), but cost data have been updated taking into account the costs escalation observed over the last years. The additional investment costs for capture at coal power plants are in the range from USD 700 to 1 300/kW for early commercial plants in 2015/2020, which equals roughly 30 to 70% of the costs for a plant without capture. A similar cost increase in relative terms can be observed between gas power plants with and without capture.

The wide range in the estimates of investment costs is based on the fact that so far no power plant with capture has been built on a commercial scale. A further aspect contributing to this uncertainty is the cost increase, which could be observed for conventional power plants over recent years, which has been discussed earlier. Under the BLUE scenario, the construction rate of new coal power plants remains roughly constant over the scenario horizon, which would ease the supply situation for boilers, the most expensive component with a share of around one third of the total coal power plant costs (NETL, 2007). Taking this and also learning effects between 2015 and 2030 into account, a cost decrease of 20-25% has been assumed for coal capture plants between 2015 and 2030.

Table 10.2 gives an overview of expected technical and economic characteristics for different capture plants. The electricity generation costs of a plant with capture are compared with a reference plant, which is for coal steam and coal IGCC plants an ultra-supercritical coal power plant without capture and for gas a combined-cycle plant without capture. The additional electricity costs for coal are in the range from USD 0.03/kWh to USD 0.06/kWh, while for gas-fired plants the additional costs vary between USD 0.02/kWh and USD 0.04/kWh.

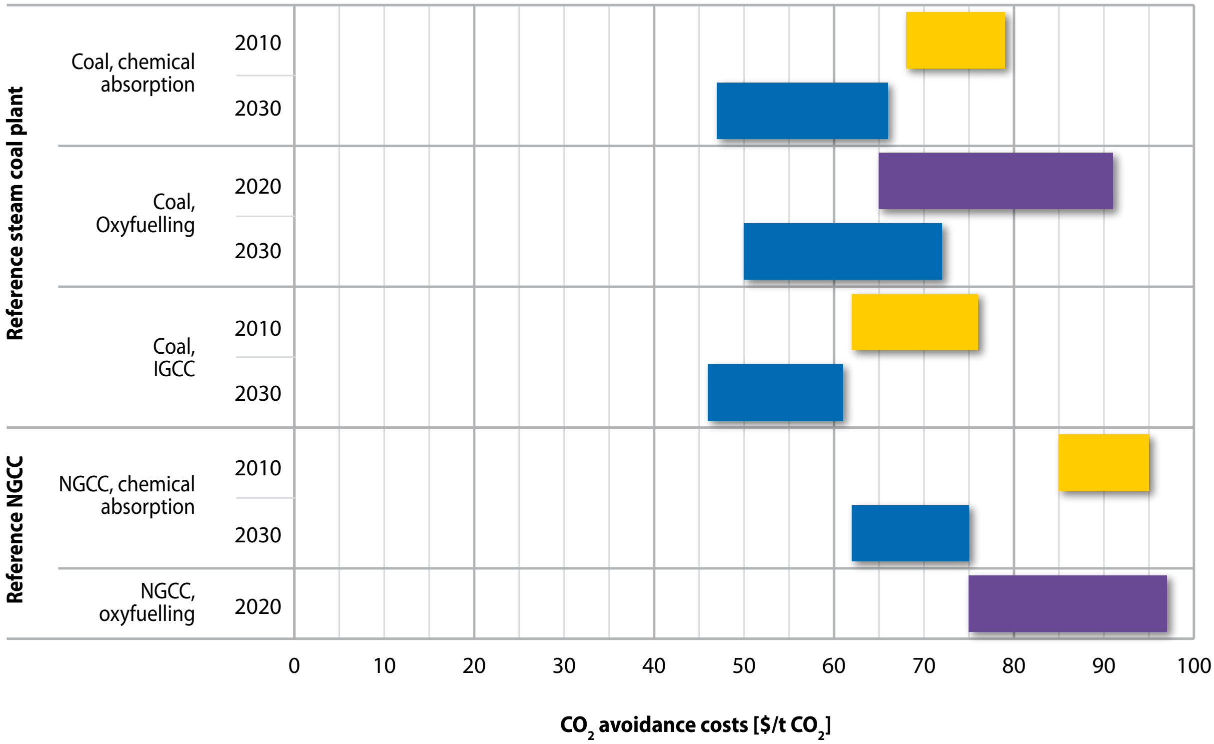
Table 10.2: Technical and economic characteristics of power plants with carbon capture

Technology	Start	Investment costs		Efficiency LH.V [%]	Eff. diff. to reference plant LHV [%]	Capt. rate [%]	LCOE	
		With capture [USD/kW]	Reference plant [USD/kW]				Capture plant [USD/MWh]	Reference plant [USD/MWh]
Coal, Steam cycle, CA	2015	3 100-3 700	2 000-2 400	36	10	85	104-118	63-71
	2030	2 150-3 250	1 500-2 300	44	8	85	76-102	51-66
Coal, Steam cycle, Oxy-combustion	2020	3 000-4 200	1 750-2 350	36	10	90	100-128	58-70
	2030	2 300-3 500	1 500-2 300	44	8	90	79-108	51-66
Coal, IGCC, Selexol	2015	3 000-3 700	2 000-2 400	35	11	85	102-119	63-71
	2030	2 200-3 200	1 500-2 300	48	4	85	75-98	51-66
Gas, CC, CA	2015	1 300-1 600	800-1 000	49	8	85	103-110	78-82
	2030	950-1 350	600-1 000	56	7	85	86-95	70-75
Gas, CC, Oxy-combustion	2020	1 400-1 800	700-1 000	48	10	95	107-116	75-81

Note: Based on a discount rate of 10%, lifetime of 40 years for coal plants, 30 years for gas plants and annual operating and maintenance costs of 2% of investment costs for reference plants and 4% for capture plants. Investment costs include owner's costs and contingencies. Electricity generations costs include interest during construction based on a construction period of 4 years for coal plants and 2 years for gas plants. CO_2 price: USD 30/t CO_2. Gas price: USD 11/MBtu, coal price: USD 90/tonne. CA: Chemical absorption, CC: Combined-cycle, IGCC: Integrated gasification combined-cycle.

The CO_2 avoidance costs in 2030 compared to the reference plant are for coal in the range of USD 50/t CO_2 to USD 70/t CO_2 and for gas plants in the period 2020-2030 between USD 60/t CO_2 and USD 100/t CO_2 (Figure 10.4). One has to note, that the avoidance costs are influenced by the chosen reference technology, which is supposed to be replaced by the power plant with capture, and its technical and economic characteristics. Assuming that a gas plant with CO_2 capture substitutes a coal power plant, instead of a gas plant without capture, the avoidance costs for gas plants decline to USD 50/t CO_2 to USD 70/t CO_2.

Figure 10.4: CO_2 avoidance costs for different coal and gas power plants between 2010 and 2030 (extended)



10.4 Demonstration and deployment of CCS

Successful demonstration and rapid deployment of CCS in the next 10 to 15 years is essential in order to contribute substantially to CO_2 emission reduction in the long-term. So far, no power plant with CO_2 capture operates on a commercial scale. Although many of the technology components involved in capturing and storing CO_2 have been applied for many years in large scale plants (e.g. coal gasification to produce chemicals, chemical absorption in the food industry), the integration of the different components needed to capture CO_2 in the power plant design has not been demonstrated on a commercial scale. Also, the integrity of the various methods to store CO_2 storage has to be verified; in addition legal and regulatory issues related to the transport and storage of CO_2 have to be addressed in many countries. To tackle these challenges, demonstration projects are crucial to gain more experience of building and operating CCS facilities. A recent roadmap for CCS presented by the IEA (IEA, 2009) concludes that to reach the 50% CO_2 reduction by 2050 in the BLUE scenario 38 CCS projects in power generation have to operate by 2020. In the following decade, the deployment has to be accelerated reaching a level of 3 500 power plants with CO_2 capture in 2030. While initially, given the investment needs for the CCS technology, its demonstration and deployment will take place in OECD countries, the technology must also spread rapidly in the developing world to contribute there to emission reductions given the dominance of coal fired power in a number of these countries. In parallel to demonstration and deployment, research and development has to address the improvement of the overall efficiency of fossil power generation and the reduction of the efficiency losses related to CO_2 capture.

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Synthesis report on other studies of the levelised cost of electricity

11.1 Introduction

There are many studies that evaluate the levelised cost of electricity for alternative generating technologies. This paper provides a brief review of results from a selection of the more recent ones, and draws out a number of insights from a comparison across the studies. The reports analysed are:

MIT (2003), *Future of Nuclear Power,* Cambridge, United States.

CERI (2004), *Levelized Unit Electricity Cost Comparison of Alternate Technologies for Baseload Generation in Ontario,* Canadian Energy Research Institute, Calgary, Canada.

RAE (2004), *The Cost of Generating Electricity,* Royal Academy of Engineering, London, United Kingdom.

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EPRI (2008), *Program on Technology Innovation: Power Generation (Central Station) Technology Options* – Executive Summary, Electric Power Research Institute, Palo Alto, United States.

EC (2008), *Energy Sources, Production Costs and Performance of Technologies for Power Generation, Heating and Transport,* European Commission, COM(2008)744, Brussels, Belgium.

House of the Lords (2008), *The Economics of Renewable Energy,* 4th Report of Session 2007-08, Vol. I: Report, Select Committee on Economic Affairs, London, United Kingdom.

MIT (2009), *Update on the Cost of Nuclear Power,* Cambridge, United States.

Tables 11.1 and 11.2 show the levelised costs reported in these studies as well as overnight cost, fuel cost and capacity factor. Table 11.1 covers the traditionally dominant generating technologies: nuclear, pulverised coal, and gas, as well as coal-fired integrated gasification combined cycle (IGCC) and biofuels. Table 11.2 covers various wind, hydro and solar technologies.

Table 11.1a: LCOE for nuclear, pulverised coal, IGCC, gas and biomass (different studies)

		MIT 2003	CERI 2004	RAE 2004	University of Chicago 2004	IEA/NEA 2005	UK DTI 2006
		[C]	[D]	[E]	[F]	[G]	[H]
Nuclear							
Overnight cost	$/kW	2 208	1 778-252	2 233	1 299-1 948	1 179-2 717	2 644
Fuel cycle cost [A]	$/MWh	6.5	2.8- 4.1	7.8	5.8	3-12.7	7.5
Capacity factor		85%	90%	>90%	85%	85%	85%
LCOE	**$/MWh**	**74**	**56-67**	**44**	**51-77**	**33-74**	**71**
Pulverised coal							
Overnight cost	$/kW	1 435	1 212	1 592	1 287	778-2 540	1 657-1 725
Fuel price	$/GJ	1.3	1.4	2.3		0.2-3	2
Capacity factor		85%	90%	>90%		85%	90%
LCOE	**$/MWh**	**47**	**45**	**51**	**36-44**	**28-75**	**51-53**
IGCC							
Overnight cost	$/kW			1 942	1 448	1 479-2 096	1 935-1 725
Fuel price	$/GJ			2.3		1.4-2.8	2
Capacity factor				>90%		85%	90%
LCOE	**$/MWh**			**62**		**41-58**	**53-60**
Gas [B]							
Overnight cost	$/kW	552	539	583	639	3 94-1 115	827
Fuel price	$/GJ	3.7	4.5	4.2	3.5-4.6	3.8-6.1	6.5
Capacity factor		85%	90%	>90%		85%	85%
LCOE	**$/MWh**	**45**	**57**	**43**	**38-49**	**44-69**	**66**
Biomass							
Overnight cost	$/kW			3 573		1 840-2 358	
Fuel price	$/GJ			1.3			
Capacity factor						85%	
LCOE	**$/MWh**			**131**		**54-109**	

Table 11.1b: LCOE for nuclear, pulverised coal, IGCC, gas and biomass (different studies)							
		MIT 2007	CBO 2008	EC 2008	EPRI 2008	House of the Lords 2008	MIT 2009
		[I]	[J]	[K]	[L]	[M]	[N]
Nuclear							
Overnight cost	$/kW		2 405	2 552-4 378	3 980	3 000	4 000
Fuel cycle cost [A]	$/MWh		9	10.5	8.2	8.8	8
Capacity factor			90%	85%	90%	77%	85%
LCOE	**$/MWh**		**73**	**65-110**	**73**	**90**	**84**
Pulverised coal							
Overnight cost	$/kW	1 332-1 415	1 529	1 295-1 865	2 450	2 140	2 300
Fuel price	$/GJ	1.5	1.7	2.8	1.7	4.1	2.5
Capacity factor		85%	85%	85%	80%	81%	85%
LCOE	**$/MWh**	**49-50**	**56**	**52-65**	**64**	**82**	**62**
IGCC							
Overnight cost	$/kW	1 487.8		1 813-2 137	2 900		
Fuel price	$/GJ	1.5		2.8	1.7		
Capacity factor		85%		85%	80%		
LCOE	**$/MWh**	**53**		**58-71**	**70**		
Gas [B]							
Overnight cost	$/kW		699	622-946	800	1 046	850
Fuel price	$/GJ		6.1	7.7	7.6-9.5	7.7	6.6
Capacity factor			87%	85%	80%	81%	85%
LCOE	**$/MWh**		**58**	**65-78**	**73-87**	**78**	**65**
Biomass							
Overnight cost	$/kW			2 617-6 580	3 235	3 674	
Fuel price	$/GJ			2.8-5	1.16-2.1	26	
Capacity factor				85%	80%	80%	
LCOE	**$/MWh**			**104-253**	**73-86**	**180**	

Notes:

– The data reported are for the base case scenario without CCS and with financial assumptions given in Table 11.3.

– All values are in USD 2007. The data reported in the studies in different currency and/or different years were converted in USD 2007 using the annual average exchange rate and a 2% annual inflation rate.

– All data are exclusive of carbon penalties.

– The data missing are not reported in the studies.

– [A] Fuel cycle cost includes all the cost from uranium mining to waste disposal except for UK DTI 2006 and House of the Lords 2008 where it does not include waste disposal.

– [B] Gas is combined cycle gas turbine.

– [C] Nuclear fuel cost has 0.5% real escalation rate; gas fuel cost has a 1.5% real escalation rate.

– [D] We use the exchange rate used in the study that is 0.70 USD/CAD; the data are for the base case scenario for merchant plants; nuclear lower value is for ACR-700, nuclear higher values for CANDU 6; gas price has a 1.8% real escalation rate.

– [E] The data reported are for the “current” scenario; we assume the data are in GBP 2003; biomass is fluidised-bed combustion of poultry litter; we consider that the heating value of a Kg of poultry litter is 0.01 MJ.

– [F] The range of nuclear overnight depends on different first-of-a-kind engineering costs; LCOE for coal also includes IGCC.

– [G] LCOE are for the base case with 10% cost of capital; fuel cost for coal and gas refer to assumption in year 2010; biomass includes 2 landfill gas plants.

– [H] Overnight cost for nuclear includes decommission cost; fuel cycle cost does not include waste disposal; we consider that the heating value of a Kg of coal is 24 MJ.

– [I] The range of values refers to different technologies.

– [J] Coal and gas data are for conventional coal and conventional gas.

– [K] The data are for LCOE in year 2007 for the moderate fuel price scenario; overnight for nuclear includes decommission cost; biomass is biomass combustion steam cycle.

– [L] The data are for LCOE in year 2015; overnight cost includes financial cost; we consider that the heat power of nuclear is 10 300 BTU/kWh.

– [M] We assume the data are in GBR 2007; fuel cycle cost does not include waste disposal.

– [N] Nuclear fuel cost has 0.5% real escalation rate; gas fuel cost has a 1.5% real escalation rate.

Table 11.2: LCOE for wind, hydro, solar PV and solar thermal (different studies)		RAE 2004	IEA/NEA 2005	UK DTI 2006	EC 2008	House of the Lords 2008	EPRI 2008
		[A]	[B]		[C]	[D]	[E]
Onshore wind							
Overnight cost	$/kW	1 437	1 056-1 769	1 539	1 295-1 775	2 222	1 995
Capacity factor		35%	17-38%	33%	23%	27%	33%
LCOE	**$/MWh**	**104**	**50-156**	**154**	**97-142**	**146**	**91**
Offshore wind							
Overnight cost	$/kW	1 787	1 772-2 838	2 878	2 267-3 562	3 148	1 995
Capacity factor		35%	40-45%	33%	39%	37%	33%
LCOE	**$/MWh**	**140**	**71-134**	**101**	**110-181**	**162**	**91**
Hydro							
Overnight cost	$/kW		1 734-7 561		1 166-8 549		
Capacity factor			50%		50-57%		
LCOE	**$/MWh**		**69-262**		**45-240**		
Solar PV							
Overnight cost	$/kW		3 640-11 002		5 311-8 938		
Capacity factor			9-24%		11%		
LCOE	**$/MWh**		**226-2 031**		**674-1 140**		
Solar thermal							
Overnight cost	$/kW		3 004		5 181-7 772		4 600
Capacity factor			9-24%		41%		34%
LCOE	**$/MWh**		**292**		**220-324**		**175**

Notes:
– The data reported are for the base case scenario without CCS and with financial assumptions given in Table 3.
– All values are in USD 2007. The data reported in the studies in different currency and/or different years were converted in USD 2007 using the annual average exchange rate and a 2% annual inflation rate.
– All data are exclusive of carbon penalties.
– [A] The data reported are for the "current" scenario; we assume the data are in GBP 2003; for wind the LCOE includes the cost of a backup gas power plant that supplies energy to reach 100% of capacity factor.
– [B] LCOE are for the base case with 10% cost of capital.
– [C] The data are for LCOE in year 2007 for the moderate fuel price scenario; the range of costs for hydro considers different configurations, from the building a new facility, the extension of an existing facility and the powering an existing hydro scheme; for solar thermal the LCOE includes the cost of a backup gas power plant that consumes 385 TJ per year.
– [D] We assume the data are in GBP 2003.
– [E] The data are for LCOE in year 2015; EPRI calculates LCOE for onshore and offshore wind power plants together; overnight cost includes financial costs.

In order to make sense of the results from each study, the data must be read with a clear understanding of the complexities of the electricity industry. It is also important to keep in sight the different goals of the various studies. Here we present some of the major factors to take into consideration.

First, electricity is not as homogeneous a commodity as one might imagine. Certain technologies may be best suited for producing baseload electricity. Others are more flexible and suited to responding to variable demand. Still other technologies, such as wind and solar, provide intermittent power, which has a value that depends upon how its stochastic profile matches the stochastic profile of demand and the flexibility of other sources of supply. Faced with this diversity, some studies choose to construct a horse race among a few selected technologies that are comparable. For example, the MIT 2003, CERI 2004, CBO 2008, University of Chicago 2006, MIT 2009 limit their focus to baseload technologies; other technologies producing other types of electricity are not considered. An alternative approach tries to include a broader array of technologies by forcing comparability – for example, by calculating a cost for wind and solar technologies that includes the cost of providing backup power, whether in the form of a stand-by natural gas generator or in the form of storage. This approach is used in RAE 2004 for wind and EC 2008 for solar thermal. The other studies report the cost of wind or solar without backup, leaving the reader to understand the difference in the type of power that is produced.

Even within a given technology class, such as coal-fired electricity, a broad array of specific alternatives is available. For coal, this includes variations on pulverised coal plants, IGCC, and fluidised bed, among others. The most economic choice of an alternative may depend upon a host of context specific factors. Some alternatives are suited to specific kinds of fuel – fluidised-bed combustion, for example, is well suited to high-ash coals, low-carbon coal waste and lignite. Other technologies are well suited to reducing emissions of key pollutants, as advocates of IGCC claim. Therefore, some studies focus on presenting information for the full array of alternatives, without intending a generalising comparison of the calculated levelised cost figures. MIT 2007 belongs to this class of studies. It analyses all main coal technologies and it calculates the levelised cost for each one. The reader is intended to understand that the best technological option depends on many factors besides the reported levelised cost, including the kind of fuel available or emissions regulations applicable to a variety of pollutants. Indeed, the true levelised cost for a given coal plant will depend upon specific factors about the coal used, and these studies are generally forced to select a benchmark type of coal. The informed reader understands that the actual levelised cost of a real plant design will depend upon the choices made for that plant.

Idiosyncratic considerations are especially significant for technologies like hydro, wind and solar. The cost of building a hydropower plant is very sensitive to the specific characteristics of the site. Moreover, the overnight cost per MWh is very sensitive to the size of the plant. Therefore, it is difficult to settle on the features of a generic plant for which a levelised cost is to be calculated. One way to tackle this problem is to specify the size of the plant being analysed. EC 2008 reports results for hydro by dividing the technology into two buckets, large scale (plants above 10MW) and small scale (plants below 10MW). IEA/NEA 2005 focuses primarily on small scale hydropower plants. Calculating the levelised cost for wind power faces a similar problem, since the site where the wind farm is located plays an important role. In particular, there is a significant difference in cost between onshore and offshore power plants. Consequently most of the studies analyse the two cases separately.

Another important factor in interpreting studies on the levelised cost for different technologies is the volume of data available on each. There are many data points for technologies that are relatively mature, like pulverised coal, as well as for a few more recent technologies, like combined cycle gas turbine (CCGT), for which many units have been built in recent years. On the other hand, novel technologies, like solar, are less tested and the paucity of data on actual builds makes it harder to reliably estimate the current cost. In addition, recent cost data seems less relevant for a novel technology undergoing faster innovation and improvements than more mature technologies. Some studies address this by distinguishing between the cost for first-of-a-kind and Nth-of-a-kind plants. In University of Chicago 2004, for example, different overnight costs are assumed for nuclear power plants depending on the maturity of the design. For more advanced designs first-of-a-kind engineering costs are added to overnight cost. In EC 2008, it is assumed that a technology's cost moves along a learning curve. A levelised cost of electricity is calculated for power plants that start operating in different year (2007, 2020 and 2030) but use the same technology. They consider that in year 2020 and 2030 the technology is more mature and less expensive, and so the overnight cost estimated for year 2020 and 2030 is less expensive than for year 2007.

Geography is also an important determinant of the levelised cost for different technologies since input costs often vary by country and geographic region. Therefore, many studies focus on a specific region. MIT 2003 and 2007, CBO 2006, University of Chicago 2004, EPRI 2008 focus on the United States. CERI 2004 focuses on Canada. RAE 2004, UK DTI 2006 and House of Lords 2008 focus on the United Kingdom. EC JRC 2008 focuses on the European Union. In contrast, the IEA/NEA 2005 study collects data from more than 130 recently built or planned power plants in 15 different countries. That study, therefore, provides useful information on how construction costs, operating costs, fuel costs and hence levelised cost, vary from country to country. No electricity generating option has the lowest cost worldwide.

It is necessary to recognise that studies also differ on the assumptions made about the forecasted values for key inputs, in particular, the forecasted fossil fuel cost. This is a crucial point because for some technologies, especially natural gas and to some degree coal, the levelised cost highly depends on fuel cost. Most studies make their own explicit assumptions about a forecasted fuel price or a range of fuel price scenarios. EC JRC 2008 considers two different fuel price scenarios based on the projections of the European Commission. The IEA/NEA 2005 results reflect each country's different assumptions about fuel price.

Another key input on which important differences may arise is the discount rate or cost of capital used to levelise the costs incurred in different years across the time profile of electricity generation. Table 11.3 shows the real discount rates employed across the different studies considered here. In some cases the discount rate was originally reported in real terms, in others we have translated the reported nominal rate to a real rate in order to facilitate the comparison across studies. Some studies simply report the discount rate they applied, while others report the combination of financial assumptions used to arrive at the chosen rate. When a methodology is detailed, overwhelmingly it is the weighted average cost of capital (WACC) formula. The inputs to this formula are the cost of debt, R_D, the cost of equity, R_E, the share of debt in the financing of the plant, D/V, and the tax rate, t: $WACC=(D/V)\ R_D\ (1-t) + (E/V)\ R_E$, where $D+E=V$. The share of debt in the financing of the plant can vary across technologies, as can the costs of debt and of equity.

There are three things to highlight in how a discount rate or cost of capital is selected. First, the cost of capital for a project depends upon the institutional setting in which the project is operated. Three different settings are commonly discussed. They are (i) state ownership, (ii) rate-of-return regulated utilities, and (iii) the merchant model, in which the power plant sells its power into a competitive wholesale market. The received wisdom is that the cost of capital is lowest for state ownership and highest for the merchant model. In some respects, a lower discount rate may reflect risks that have been shifted off from the project's owners and creditors, but that still fall on some party or the other. For example, the risks that the shareholders of a regulated utility are able to avoid may simply be risks that the utility's ratepayers now assume. Shifting risks does not truly lower the cost of the project from a macro or social perspective. Therefore, the calculated levelised cost of state-owned plants may not truly represent the full cost, just the lower cost that the project must recoup in order to pay its shareholders and creditors. The ratepayers bear a cost that has not been included in the levelised cost calculation. Whether state ownership actually lowers the total risks and therefore the total costs, or simply shifts the risks is debatable. For this reason, a cost of capital for the merchant model has gained some popularity, although this is not universally accepted. All of the studies reviewed in this report calculate the levelised cost for a merchant model. Only CERI 2004 has also done analysis for state ownership model as well.

Table 11.3: Financial assumptions in different studies								
		Cost of capital	Cost of debt	% of debt	Cost of equity	% of equity	Tax	Inflation
MIT 2003 [A]	Nuclear	6.80%	4.90%	50%	11.70%	50%	38%	3%
	Coal & gas	4.60%	4.90%	60%	8.70%	40%	38%	3%
CERI 2004 [A]		8.80%	8%	50%	12%	50%	30%	2%
RAE 2004 [B]		7.50%						
University of Chicago 2004 [C]	Nuclear	7.40%	6.80%	50%	11.70%	50%	38%	3%
	Coal & gas	5.00%	3.90%	50%	8.70%	50%	38%	3%
IEA/NEA 2005		5%/10%						
UK DTI 2006		10%						
MIT 2007		5.20%	4.40%	55%	9.30%	45%	39.20%	2%
CBO 2008 [A]		10%	8%	45%	14%	55%	39%	2%
EC JRC 2008		10%						
EPRI 2008 [C]		5.50%	4.40%	50%	8.30%	50%	38%	2.50%
House of the Lords 2008		10%						
MIT 2009	Nuclear	6.80%	4.90%	50%	11.70%	50%	37%	3%
	Coal & gas	4.70%	4.90%	60%	8.70%	40%	37%	3%

Note:
– The values are for the base case scenario for the merchant model.
– All the figures are in real values.
– [A] The data refer to the initial values.
– [B] The cost of capital is in nominal value, other financial data are not reported.
– [C] The value of inflation used in the studies was found in: MIT (2007), The Potential for a Nuclear Renaissance: The Development of Nuclear Power Under Climate Change Mitigation, by Nicolas Osouf, Cambridge, United States.
– [D] EPRI values come from private colloquy with EPRI executives.

Second, some studies specify a real discount rate without explicitly reporting their assumptions about a rate of inflation or a tax rate. Given that a real discount rate is being used, it may seem as if an assumption about a rate of inflation is superfluous, but this may not be universally true.[1] Third, in some cases the debt ratio is assumed to decline through time as the debt amortises long before the plant reaches the end of its useful life. In these cases, the debt ratio that is reported is the initial ratio. This is true for MIT 2003, CERI 2004, CBO 2006 and University of Chicago 2004. A side effect of this is that the effective cost of capital that is applied in the levelised cost calculations is changing through the life of the project. Typically, the effective cost of capital is rising. This generally biases down the value of the future cash flows from electricity sales and so exaggerates the levelised cost. It is often difficult to discern that this is the case in a report unless the full details of the calculation are somehow made available to the public.

Finally, it is important to mention that another element which many studies consider is the prospects of carbon penalties, e.g., MIT 2003, CERI 2004, RAE 2004, University of Chicago 2004, UK DTI 2006, MIT 2007, CBO 2006, and EC 2008. The presence of a tax on carbon emissions raises the cost of producing electricity for coal and gas power plants, with coal plants being especially hard hit. This makes technologies with few or none carbon emissions more competitive, including renewable and nuclear, as well as coal or gas with carbon capture and storage (CCS). MIT 2007, UK DTI 2006, CBO 2006, EC 2008 also calculated the levelised cost of electricity for power plant with CCS. The size of the penalty that is necessary to reverse an apparent cost advantage for coal depends on all the factors already discussed above.

1. Under the US generally accepted accounting principles (GAAP), for instance, the present value of a project's after-tax cash flows are almost certainly affected by the assumed rate of inflation because depreciation tax shields are generally determined on the basis of the nominal cash flows, and therefore the present value of these tax shields will decrease as the inflation rate increases. If taxes are included in the calculation of levelised costs, the tax rate will also be a determinant of the present value of a project's after-tax cash flows because the significance of the present value discrepancy between the timing of the original capital investment and the expensing of the depreciation tax shields depends on the level of the tax rate.

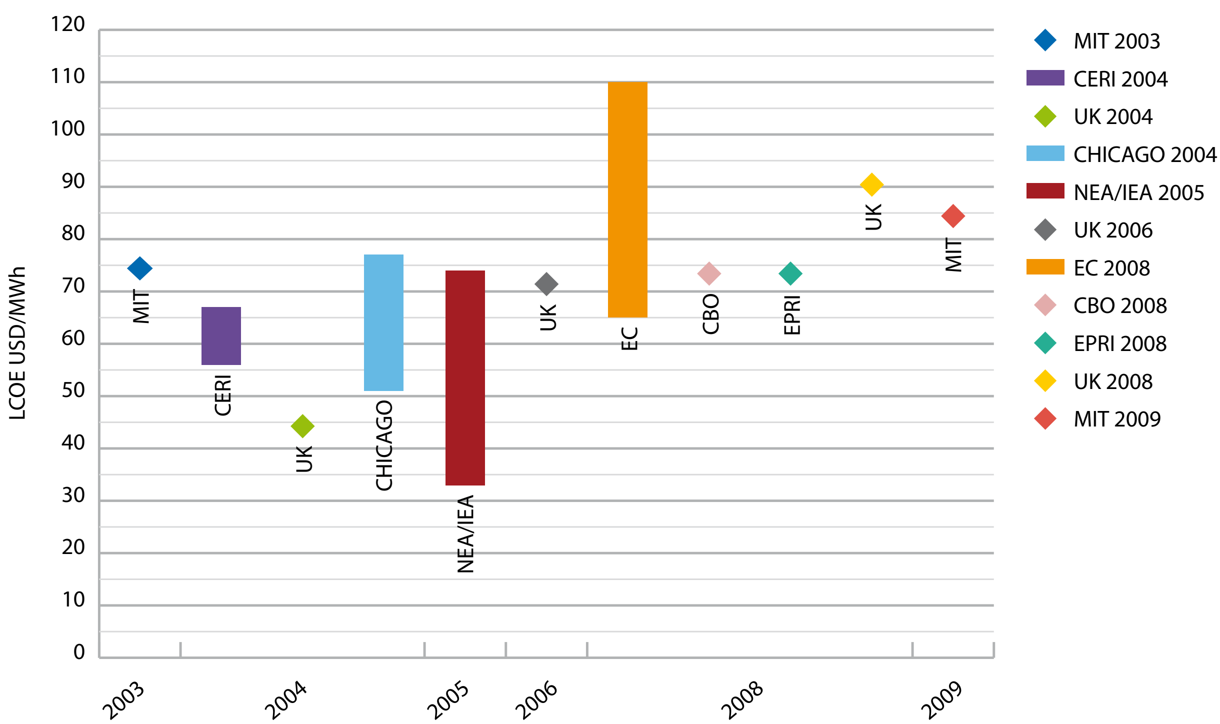
11.2 Common lessons

Although the surveyed studies were made in different years and with different approaches, it is nevertheless possible to draw a few general conclusions.

First, all the studies agree on the key factors to which the levelised cost is most sensitive. These factors can be divided into three categories: investment cost[2], fuel cost and non-fuel O&M cost. The most important categories are investment cost and fuel cost. Some kinds of energy (hydro, wind and solar), do not have fuel cost, so levelised cost depends only on investment cost and O&M cost. Nuclear has a very low fuel cost, but it is very sensitive to investment cost. On the other hand gas and coal are more sensitive to fuel cost and so to fuel price. In particular gas has very high sensitivity to fuel cost due to its relatively low overnight cost.

For nuclear, coal and gas technologies, an upward trend in cost evolution in recent years is apparent. The surveyed studies were published in different years, from 2003 to 2009. Figures 11.1-11.4 report the levelised costs for nuclear, pulverised coal, IGCC and gas versus the year of publication of the studies. For these technologies, the levelised costs estimated in the earlier studies tend to be lower than the ones estimated in the most recent ones. This specific time period exhibited a surprising and enormous increase in the price of key inputs for nuclear, coal and gas, so that there was a substantial increase of the costs for producing electricity. In particular, for nuclear there was a high increase in overnight cost, for gas in fuel cost and for coal both in overnight and fuel costs.

Figure 11.1: LCOE for nuclear (different studies)



2. Investment costs include overnight construction costs as well as the implied interest during construction (IDC). Both overnight costs and discount rate used in levelised cost calculation thus play an important role in the economics of power generation projects.

Figure 11.2: LCOE for pulverised coal (different studies)

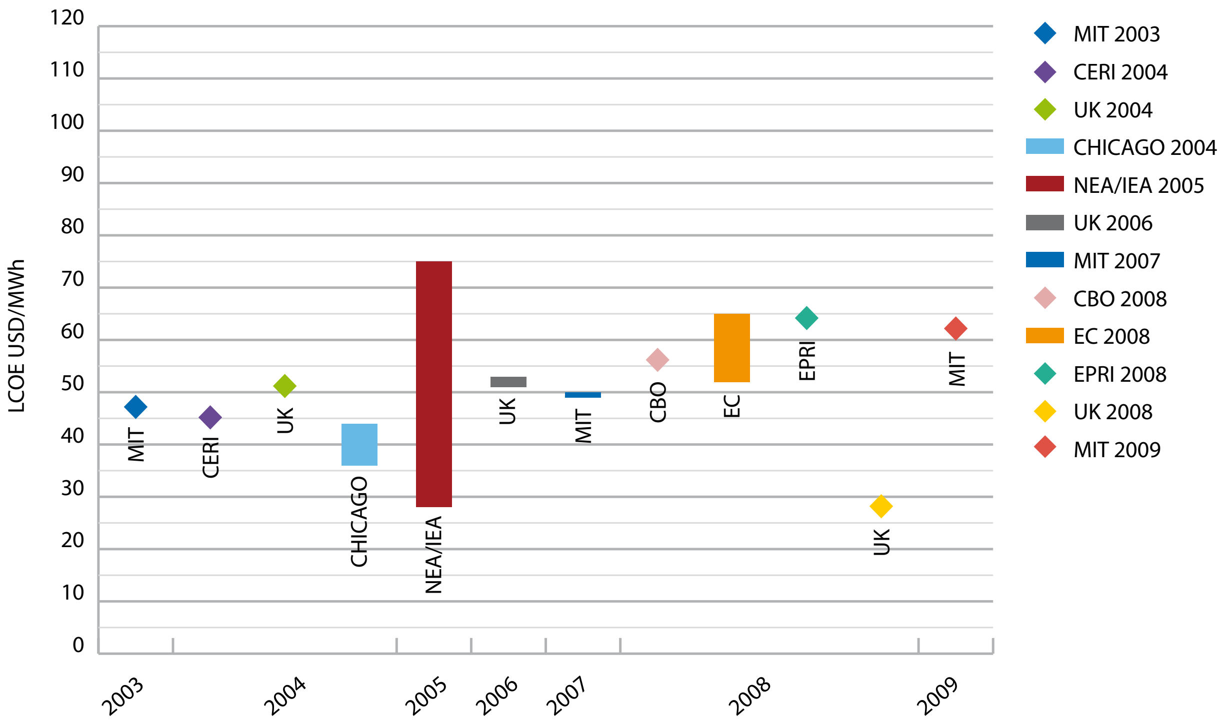


Figure 11.3: LCOE for IGCC (different studies)

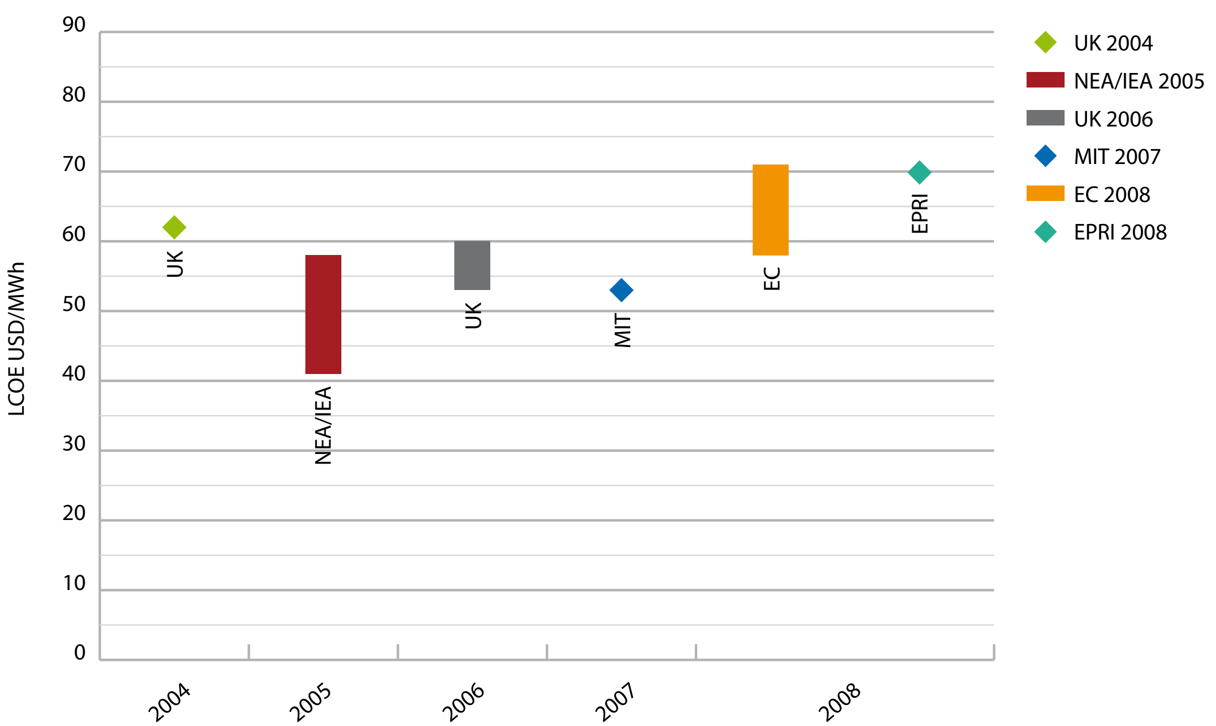
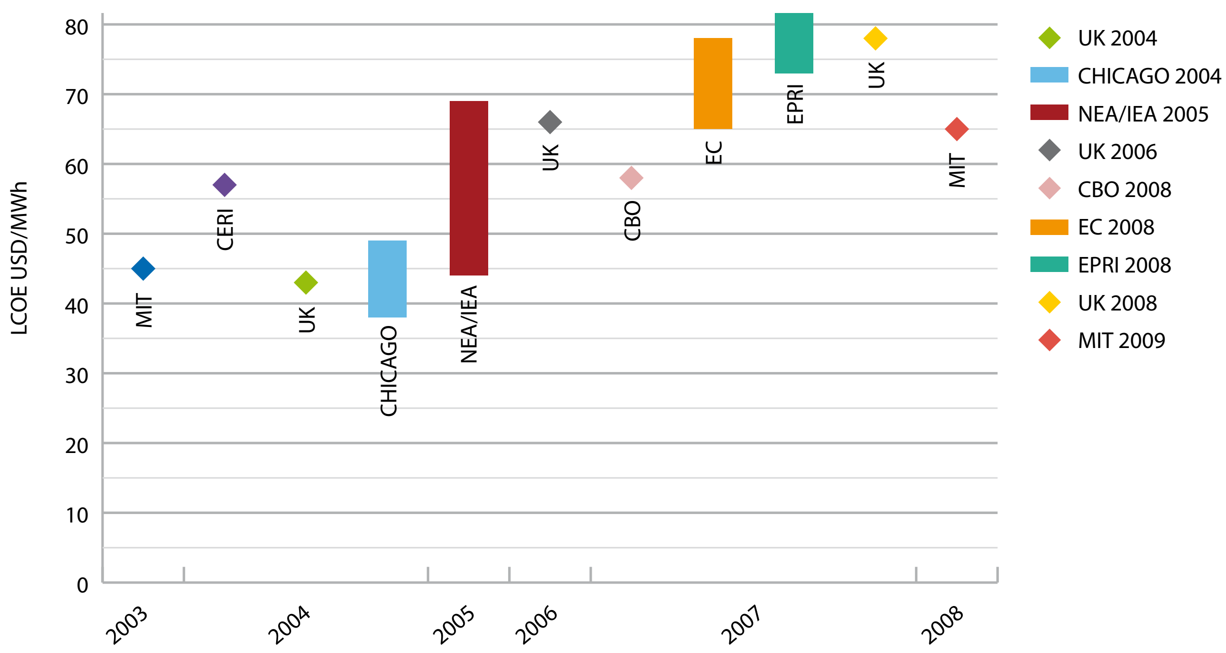
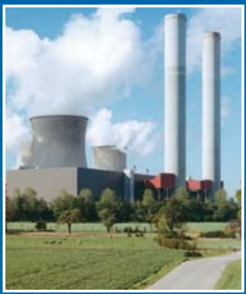
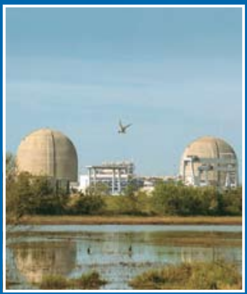


Figure 11.4: LCOE for gas (different studies)



Regarding renewable energies, what is evident from Tables 11.2 and 11.3 is that the range of values of levelised costs is very large, much more significant than for nuclear, coal and gas. This is due to the high uncertainty on estimating their costs. For hydro this is because its cost depends strongly on the site where the power plant is constructed. For biofuels, solar and wind, it is because these technologies are relatively new and there are still few commercial plants, so less data is available. In addition, these technologies are undergoing rapid development and evolution in their cost structure. However, it is important to stress that even if gas, coal and nuclear are technologies with a longer track record, nevertheless there are always some uncertainties on estimating their costs. For nuclear, in particular, the recent history of construction of new plants is sparse, with no new nuclear power plants having been constructed in the United States since 1996. Consequently, there are important uncertainties on the costs of constructing a new nuclear power plant in the United States. For gas and coal, the volatility of fuel price makes the cost unpredictable. Finally, the prospect of carbon penalties is another uncertainty that could change the levelised cost for natural gas and especially coal-fired technologies.

Annexes


Issues concerning data from non-OECD countries and assumptions for the electricity generating cost calculations

The 2010 edition of the *Projected Costs of Generating Electricity* study, as in previous editions, includes data not only for OECD countries, but also for selected non OECD countries, namely Brazil, China, Russia and South Africa, where most of the growth in power generation is taking place. For this new edition, the Secretariat, with the assistance of the IEA Directorate for Global Energy Dialogue, identified and invited key experts from so-called BRICS countries to participate in the Expert Group providing data for their home countries and their expert advice.

All the five invited countries were involved in some way or another, although only invited experts from Brazil, Russia and South Africa were able to provide comprehensive data on generating costs for different technologies in their respective countries. A representative from the Indian Central Electricity Authority attended the first meeting of the Expert Group and helped shaping the final study and in particular defining the set of assumptions that apply to non OECD countries. For China, the Secretariat collected by itself extensive data on a wide number of plants and on key cost parameters in China using Chinese official and other public sources of information, and verified all selected data and results of the cost calculations bilaterally with the National Energy Administration, which provided useful feedback for the final publication.

The EGC study has benefited this way from a wider perspective that allows to draw some conclusions about the different cost conditions for power generation in OECD countries and key non OECD countries. Nevertheless, the results of the cost calculations for countries outside the OECD are not directly comparable to those in the OECD, as a different set of assumptions was applied. Above all, after a discussion at the Expert Group with the presence of representatives from BRICS, it was agreed that no CO_2 cost will be applied outside the OECD, given that it is unlikely that these countries will adopt in the near term any type of CO_2 pricing. In practice, new projects currently under consideration in BRICS countries do not internalise future CO_2 costs. On the other hand, in some of these countries other important environmental regulations are applicable, for example regarding air pollution, and thus they have been taken into account in the cost calculations.

Generally speaking, it was decided that for BRICS countries the LCOE will be based as much as possible on their own domestic assumptions given their very different cost conditions, for example regarding fuel prices and calorific values, or decommissioning costs. Other generic assumptions adopted in the study were applied only for the sake of minimal harmonisation, e.g. with respect to the lifetime of plants; or as default values in the absence of country reported data, e.g. regarding contingency or decommissioning costs. In the remainder of this chapter, we briefly summarise the main underlying cost issues that need to be taken into account when interpreting the results of the LCOE calculation in non-OECD countries.

Brazil

Brazilian Ministry of Mines and Energy (Secretariat for Energy Planning and Development) and on its behalf, Centrais Elétricas Brasileiras S/A (ELETROBRÁS) reported data for 7 typical plants in Brazil of which 1 is nuclear, 3 are hydro, 1 is coal-fired, 1 is gas-fired and 1 is a biomass (woodchip) plant.

Load factor

- The LCOE for baseload plants is based on a generic assumption of 85% load factor and a standard operating life (60, 40 and 30 years respectively) for nuclear, coal and gas-fired plants, same as for OECD countries. The reported load factor for nuclear plant was however 95%, with an operating lifetime of 40 years.
- In the case of coal- and gas-fired plants, Brazil pointed out that 85% load factor was above the country averages; in particular, current coal mining capacities are limited to feed these types of plants. A more accurate operating ratio for coal and gas plants in Brazil is around 60%, because the centralised dispatch is cost based. As a matter of fact, most power plants in Brazil (with installed capacity above 50 MWe) are dispatched by the National System Operator. The Brazilian power sector is predominantly composed by hydropower plants, which have lower operation costs, providing electricity to attend the baseload. In this case, the thermal power plants start operating whenever their variable cost (known as CVU) is lower than the national marginal cost, which means that they do not operate full time.
- Since thermal power plants have long term contracts, and during the last few years the national marginal cost is lower than the CVU, those power plants need to purchase the differences between the contract and the generated electricity in the spot market. Furthermore, those power plants receive monthly the required coal for their minimum monthly generation, which makes those plants relatively inflexible.
- Country average load factor for hydroelectricity is about 55%, which has been taken into account for the LCOE calculations for all the three hydro plants.

Nuclear

- Construction period for nuclear plants is 8 years. Overnight costs are BRL 291 million per year (2008) = USD 126.5 million per year and include contingency equal to 5% of the construction costs. Refurbishment amounts to BRL 36.3 million per year beginning in the 11th year of the operation cycle (during 50 years) (from 2026 to 2055). Decommissioning year is 2055. Nuclear decommissioning costs are BRL 16 163 000/year. Fuel cycle costs were not indicated in the country submission and were added as follows:
  - BRL 21.30/MWh (2008) = USD 9.26/MWh (burned–up fuel)
  - Waste management cost (~25%) disaggregated from the total fuel cycle costs.
  - Reported waste management costs:
    - 2031: BRL 69.0 M
    - 2051: BRL 368.0 M
    - 2055: BRL 368.0 M

    TOTAL: BRL 805.0 M

Hydro

- The three reported hydro plants have operating lifetimes of 30 years in the case of the small one (15 MW) and 50 years for the two larger plants (300 and 800 MW respectively).
- Hydro plants with less than 30 MW of installed capacity have a 50% discount on the transmission tariffs.

Gas

- Reported operating lifetime for gas-fired plants is 15 years. In order to make results for baseload plants more comparable, the generic assumptions for load factors and lifetimes were retained for all Brazil's baseload plants as mentioned above.
- The budget for overnight costs considers 8% as contingency covering all the uncertainty. Natural gas prices are 8.13 US$/MMBTU or BRL 14.88 (according to the 2008-2017 Energy Outlook, published by the Ministry of Mines and Energy), and they do not include taxes and commercialisation. Emissions limits are set forth by the "Resolução CONAMA 003/90" as follows.

Table A.1: Emission limits for selected airborne pollutants

Pollutant	Time	Primary level µg/m³	Secondary level µg/m³
Particulate matter PM	24 hour (1)	240	150
	Geometric Average Annual	80	60
SO_2	24 hour	365	100
	Annual Arithmetic Mean	80	40
CO	1 hour (1)	40 000	40 000
	8 hour	10 000	10 000
O_3	1 hour (1)	160	160
Smog	24 hour (1)	150	100
	Annual Arithmetic Mean	50	40
Respirable Suspended Particulate – RSP	24 hour (1)	150	150
	Annual Arithmetic Mean	50	50
NO_2	1 hour (1)	320	190
	Annual Arithmetic mean	100	100

1. No more than once a year.

Coal

- The primary fuel is coal (CE 3300) – secondary fuel is oil – which is nationally produced and has gross calorific value on dry minimum acceptable of 2 850 kcal/kg. The lower heat value is 2 450 kcal/kg. The price assumption retained for the cost calculations is BRL 60.56/tonne or USD 33.09/tonne. There are however significant internal price differences within Brazil. Prices range from USD 20/tonne for domestically produced brown (lignite) coal to USD 100/tonne of imported black coal.

Biomass

- Reported lifetime of 20 years was retained although the reported load factor (82.19%) was replaced with the standard assumption for baseload plants (85%). The price for biomass (woodchips) is BRL 21.16/tonne or USD 11.56/tonne.

China

The IEA tried to engage the China Electricity Council, as the relevant Chinese authority with a national view of power generation costs, to provide data required for *Projected Costs of Generating Electricity*. In parallel, high level contacts were established with senior officials at the National Energy Administration. Despite a very positive reaction, Chinese authorities were not able, given the limited timeframe for the completion of the 2010 edition of the study, either to submit cost data for the study or to send an expert to the Expert Group meetings. They however were timely or subsequently informed about the final results of the study for China. The research for this section was done unilaterally by the IEA Secretariat, with the help of a Chinese secondee, Mr. Alex Zhang, who carried out the relevant data research over the summer of 2009.

The Expert Group agreed to proceed on this basis in the absence of officially reported data from invited Chinese authorities, and the result, after examining hundreds of plants, is the cost data included for 20 selected plants under construction in China today (with the only exception of the Three Georges hydro plant on the Yangzi River, already completed but included due to its magnitude and importance), which is the largest sample among all of the countries in *Projected Costs of Generating Electricity*.

All reported data are based on a large number of relevant Chinese public information sources, mostly collected from the website of Beijing National Energy Administration, local energy administration, research journals, large power companies and last but not least, the China Electricity Council, including its latest annual publication on Chinese power sector. The IEA Secretariat has the complete list of external references on file and can make it available upon request. The IEA used also internal statistics and own data sources in order to make the necessary default assumptions – in the absence of more specific national or plant data – on key parameters like load factors, plant auto consumption, thermal efficiencies, fuel characteristics and prices, heat prices, etc. All the assumptions made by the Secretariat are also specified below.

Overnight costs

- For China, we assume that contingency cost has been already included in published overnight cost figures.

Plant capacity

- According to the Annual Statistic Reported of Electricity Power Industry 2008 by China Electricity Council, auto-consumption at plant is assumed to be 6.79% for coal-fired plants and 0.36% for hydro in China.
- For the rest of technologies, we use 3% for gas-fired and 0% for nuclear, solar and wind, according to international standard assumptions to calculate net capacity from reported gross installed capacity.

Load factors

- Baseload plants – nuclear, coal- and gas-fired and hydro – are assumed to run at 85% load factor according to the standard EGC study assumption.
- For solar and wind plants, expected load factors at each plant have been used for the cost calculations.

Table A.2: China power plant overnight construction cost								
Plant Name	Technology	Capacity incl. in cost estimates (MWe)	Estimated electricity gereation per year (GWh)	Overnight construction costs			Construction duration (Y)	Domestic load factor
				MCNY	MUSD	USD/kWe		
Fujian Ningde	Nuclear CPR1000	4 × 1 000		49 000.00	7 051.37	1,762.84	4	0.88
Liaoning Hongyanhe	Nuclear CPR1000	4 × 1 000		48 600.00	6 993.81	1,748.45	5	0.88
Shandong Haiyang	Nuclear AP1000	2× 1 250		40 000.00	5 756.22	2,302.49	5.7	0.88
Yumen Changma	Wind (onshore)	200		1 700.00	240.00	1,200.00	3.00	0.27
CPI Dalian Tuoshan	Wind (onshore)	33 × 1.5	115.5	530.00	76.27	1,540.81	1.25	0.27
Xianjuding	Wind (onshore)	30	51.5	330.00	47.49	1,582.96	1.2	0.20
Xinyang Jigongshan	Wind (onshore)	41 × 0.85	66.84	394.05	56.71	1,627.14	1	0.22
Pinhai	Ultra-supercritical Coal-fired	2 × 1 000		8 500.00	1 223.20	611.60	2	0.56
Xiangyang	Supercritical	2 × 600	6 600	4 680.00	673.48	561.23	2	0.56
Huadian Liuan	Supercritical	600		2 610.00	375.59	625.99	2	0.56
Putian	Gas - steam combined cycle	4 × 350	6 000	5 080.00	731.04	522.17	1.33	0.56
Shanghai Lingang	Gas - steam combined cycle	4 × 350		5 500.00	791.48	565.34	2	0.56
Guodian Anshan	Combined heat and power	2 × 300	3 900	3 000.00	431.72	719.53	1.5	
Qinghai Delingha	Photovoltaic	10	15.36	260.00	37.42	3,741.55	1.33	0.18
Qinghai Geermu	Photovoltaic	20	36	400.00	57.56	2,878.11	1	0.21
Gansu Dunhuang	Photovoltaic	10	18.05	203.00	29.21	2,921.28	1.2	0.21
Ningxia Pingluo	Photovoltaic	10	16	250.00	35.98	3,597.64	1.5	0.18
Longtan	Hydro	9 × 700	18 700	33,000.00	4,748.88	753.79	6	0.34
Three Gorges	Hydro	26 × 700	84 700	199,450.55	28,702.05	1,577.04	5.5	0.53
Yalongjiang Jinping	Hydro	4 800	24 000	29,770.00	4,284.07	892.51	6	0.57

Source: IEA own research based on a variety of sources.

Fuel prices

- Nuclear fuel cost was assumed according to the common assumption of 7 and 2.33 USD/MWh, for front-end and back-end fuel cycle respectively.
- Domestic coal prices have been estimated according to the current coal price and the trend in Qinhuangdao port. The resulting coal price assumption is 86.34 USD/tonne (600 CNY per tonne). The average calorific value of domestically produced and consumed coal in China is assumed to be 22 274 MJ/tonne, according to IEA latest Coal Information statistics.

Table A.3: Qinhuangdao domestic coal prices (CHN/t NAR)											
	Coal brand	4 May	11 May	18 May	25 May	1 June	15 June	22 June	29 June	6 July	13 July
Pre-train unloading	Datong premium blend	570-590	580-600	580-600	580-600	580-600	570-590	570-590	570-590	570-590	570-580
	Shanxi premium blend	540-560	550-570	550-570	550-570	550-570	550-565	540-560	540-550	540-540	540-550
	Shanxi blend	465-480	475-490	475-490	475-490	475-490	475-490	475-490	470-485	475-485	470-485
	General blend coal 1	405-420	405-420	405-420	405-420	405-420	390-405	390-400	385-395	385-395	385-395
	General blend coal 2	340-355	340-355	340-355	340-355	340-355	335-345	335-345	330-340	330-340	330-340
Reference price (FOB	Datong premium blend	600-620	610-630	610-630	610-630	610-630	600-620	600-620	590-610	590-605	590-605
	Shanxi premium blend	570-585	580-590	580-590	580-590	580-590	575-585	565-580	560-575	560-570	560-570
	Shanxi blend	490-505	505-520	505-520	505-520	505-520	500-515	500-515	495-510	490-505	490-505
	General blend coal 1	430-445	430-445	435-445	430-445	435-445	420-430	415-425	410-420	410-420	410-420
	General blend coal 2	365-375	365-375	365-375	365-375	365-375	355-365	355-365	350-360	350-360	350-360

Source: Qinhuangdao port authorities.

- According to China National Petroleum Corporation, domestic gas price for power section in Shanghai was 1 230 CNY/1000m^3 (4.67 USD/MBtu) in 2008.

Table A.4: West-East pipeline gas (2008)					
Destination	Sector	CNY/1 000 m³			USD/MBtu
		Ex-plant	Pipeline tariff	City gate	City gate
Henan	Industry	960	640	1 600	6.08
	Residential	560	680	1 240	4.71
Anhui	Industry	960	750	1 710	6.50
	Residential	560	750	1 310	4.98
Jiangsu	Industry	960	790	1 750	6.65
	Residential	560	940	1 500	5.70
	Power	560	620	1 180	4.48
Zhejiang	Industry	960	980	1 940	7.37
	Residential	560	980	1 540	5.85
	Power	560	720	1 280	4.86
Shanghai	Industry	960	800	1 760	6.69
	Residential	560	980	1 540	5.85
	Power	560	670	1 230	4.67

Source: China National Petroleum Corporation (CNPC).

Heat price assumption

- The domestic heat price assumption is 0.147 RMB/kWh or 19 USD2007/MWh, according to the indexed heat tariff included in the World Bank ESMAP report 330/08 published in March 2008.

Sample of data selected for China

- **CHN-N1:** 4 × 1 000 MW CPR1000 nuclear reactors in Ningde, Fujian Province. The first two reactors have begun construction on 18 February 2008, and No. 1, No. 2, No. 3, and No. 4 reactors will be commissioned in March 2012, 2013, 2014 and 2015 respectively.
- **CHN-N2:** 4 × 1 000 MW CPR1000 nuclear reactors in Dalian, Liaoning Province. The project has been started on 18 August 2007, and the first reactor will be commissioned in 2012, all others will be finished by 2014.
- **CHN-N3:** 2 × 1 250 MW AP1000 nuclear reactors in Haiyang, Shandong Province. The project started on 29 July 2008, and the No. 1 and No. 2 reactors will be commissioned in May 2014 and March 2015 respectively.
- **CHN-W1:** Onshore wind plant with a total capacity of 200 MW in Yumen, Gansu Province. The construction duration will last 36 months, starting from 2008 and for commissioning in 2010.
- **CHN-W2:** Onshore wind plant with 33 × 1.5 MW turbines in Dalian, Shandong Province. The plant will occupy 62 km^2, construction beginning 26 August 2008 and commissioning by the end of 2009.
- **CHN-W3:** Onshore wind plant with total capacity of 30 MW in Dawu, Hubei Province. The project started 18 October 2008; once commissioned by the end of 2009, the plant will generate 51.5 GWh per year.
- **CHN-W4:** Onshore wind plant with 41 × 0.85 MW turbines in Xinyang, Henan Province. The construction duration is from 2008 to 2009, and the project will generate 66.84 GWh per year after commission.
- **CHN-C1:** 2 × 1 000 MW ultra-supercritical coal-fired turbines plant in Huidong, Guangdong Province. This is the largest thermal plant in Guangdong, which planned the construction of six 1 000 MW units in two periods. The first period including two units was approved by National Development and Reform Committee (NDRC) in 7 October 2008, and will be commissioned in 2010.

- **CHN-C2:** 2× 600 MW supercritical coal-fired turbines plant in Xingyang, Henan Province. This project will be commissioned by the end of 2010.
- **CHN-C3:** 600 MW supercritical coal-fired turbine plant in Liuan, Anhui Province. The project is undertaken by China Huadian Corporation, one of the Big Five Generating Groups.
- **CHN-G1:** 4 × 350 MW gas-steam combined cycle turbines plant in Putian, Fujian Province. The firstLNG-steam combined cycle turbines project in Fujian, and the first turbine has been commissioned on 12 October 2008.
- **CHN-G2:** 4 × 350 MW combined cycle gas turbine plant in Shanghai. This is the largest gas-fired project in Shanghai with a generating efficiency of 56% and 3% self-consumption rate. The first two units will be commissioned in 2010, and another two units will finish construction and operate during the summer of 2011.
- **CHN-CHP:** 2 × 300 MW combined heat and power units in Anshan, Liaoning Province. Guodian Anshan project will invest 10 billion CNY (1.44 billion USD) in 8 × 300 MW combined heat and power units, planned to be completed in three phases. The first 2 × 300 MW units with a budget of 3.0 billion CNY (431.72 Million USD) will start construction in 2009, for commissioning in 2010. The project will generate 3.9 billion kWh electricity and supply 600 GJ heat per year, servicing 12 km^2 after commissioning.
- **CHN-S1:** Solar PV plant with 10 MW in Delingha, Qinghai Province. The project started at the end of August 2009, and will finish by the end of 2010. It will generate 15.36 MWh with 2 187.7 load hours per year.
- **CHN-S2:** Solar PV plant of 200 MW in Geermu, Qinghai Province. The first project of 20 MW started in 20 August 2009 and is expected to be commissioned in September 2010, and generate 36 GWh per year.
- **CHN-S3:** Solar PV plant of 10 MW covering 1 km^2 in Dunhuang, Gansu Province. The project will be constructed within 14 months, and is expected to generate 18.05 MWh per year.
- **CHN-S4:** Solar PV plant of 50 MW in Pingluo, Ningxia Province. The whole project will totally cost 1.25 billion CHN (17.99 million USD) for 50 MWp. The first project of 10 MWp started in 25 June 2009, and is scheduled to be commissioned in 2010, and to generate 16 GWh per year.
- **CHN-H1:** 9 x 700 MW hydro power turbines plant in Tiane, Guanxi Province, the second largest hydro project in China. The project started on 1 July 2001, and the first turbine was commissioned in May 2007. By the end of 2009, all of the 9 units will be commissioned and will generate 18.7 TWh per year.
- **CHN-H2:** 26 × 700 MW hydro power turbines plant in Three Georges on Yangzi River, the largest hydro project in China. The project started in 1992, lasted 17 years, and was finished on 29 October 2008, when the 26th turbine was commissioned.
- **CHN-H3:** Large hydro power plant with total capacity of 4 800 MW on the Yalong River, Sichuan Province. The project started in January 2007, and No. I turbine is expected to be commissioned in 2012. The construction of the whole plant will finish in 2015, and will generate more than 24 TWh per year.

Russia

Prospective costs for almost all types of generating plants using different primary energy resources were reported for *Projected Costs of Generating Electricity* by Dr. Fedor Veselov, invited by the IEA to the Expert Group as the Head of the Energy Markets Laboratory at the Russian Energy Research Institute, in charge of analysing potential investment options for the Russian government long-term energy sector planning, including the national Energy Strategy, General Plan for Electric Power Industry Allocation. Given the important role that CHP technologies traditionally play in the Russian power sector and that currently they represent nearly 37% of total installed capacity, the sample for Russia includes 5 plants using different CHP technologies out of a total 11 reported projects.

Capital costs – coverage and uncertainties

- Construction cost estimates were prepared on the basis of pre-feasability and project data from the engineering and developer companies, the latest investment programme for thermal generation (announced by RAO EED in 2008), as well as regular monitoring of EPC and EPCM contracts. All overnight construction cost data are expressed in 01/01/08 roubles. The applied exchange rate is 24.85.
- Project contingency is estimated at 10% of construction costs. This usually captures most of the risks related with the individual project implementation at pre-construction and construction stages.
- All presented cost data correspond to the green-field plant projects to be located in Central Russia (Moscow area), scaled for one unit (except obviously, for wind), and are limited to the plant-level, thus excluding system (grid) costs. A number of factors explain the differences in capital costs of (technologically) similar projects that can be observed in reality:
  - Brown-field or green-field construction. New units commissioned at an existing site may be 10-15% cheaper than a similar green-field plant, with a considerable cost saving potential arising from existing auxiliary facilities and infrastructure.
  - System costs of grid reinforcement in average may add near 10% of capital costs, but may reach 25-30% for green-field plants remote from consumption centers. Inclusion of grid reinforcement into plant capital costs is a specific project issue defined in agreement with the Federal Grid Company (Russian TSO).
  - Geographic location of the specific plants may cause additional costs related to equipment transportation expenses, regional differences in prices of construction materials, as well as labor costs. Construction costs increase considerably moving to the east of Russia – due to the transportation costs and geological and climate conditions. Due to the effect of regional context on the plant economics, generation costs can be expected to increase by 20-25% moving from Moscow area to Siberia, and even by 50-100% for the extreme climate conditions in the Northern or Eastern regions.

Load factors

- LCOE results are calculated under the general assumption of 85% annual capacity factor (except for renewables). The national assumptions used for screening analysis in the Russian power sector long-term forecasts assume 74% for all types of plants except for CHP. For CHP plants a lower 63% load factor is assumed, as a period of their operation is in co-generation mode.

Fuel prices – pricing and regional issues

- Gas prices in Russia are and in the near to medium term will remain regulated, but the Government has recently allowed significant increases in regulated prices. It is assumed that after 2015 gas prices will be equal to the netback EU export gas prices.
- Coal prices will be mainly formed as a sum of coal production costs and regulated railway tariffs.
- Due to the large territory, fuel prices exhibit a significant difference across the regions of Russia. Gas and coal prices at the production areas are often twice lower than in the Central Russia due to the transportation costs (pipeline for gas and railroad for coal).
- For the economic evaluation fuel costs are estimated based on the fuel prices corresponding to the Central Russia (Moscow area) where they will be high enough to ensure effective inter-fuel competition in electricity production between gas, coal and nuclear sources:
  - Gas prices are estimated at 5 000 Rubles or ~200 USD/1000 cubic meters (USD 5.97 per GJ or USD 6.30 per MMBtu).
  - Coal prices are estimated at 1 940 Rubles or ~78 USD/tce (USD 2.66 per GJ or USD 2.81 per MMBtu).

Heat price assumption

- In 2007 the average heat tariff in Russia was about 15 USD/Gcal of heat (12.9 USD/MWh). For the period starting with 2015, the year of commissioning, and throughout the economic lifetime of the power plants examined in the study, the forecasted heat price is 30 USD/Gcal of heat (25.8 USD/MWh).

Carbon costs

- Russia still has a considerable gap between actual CO_2 emissions and 1990 target level. At present, actual energy policy does not yet consider measures for strong economic stimulation of low- or zero-carbon technologies, like CO_2 prices, taxes or subsidies for renewables. It is obvious that the introduction of CO_2 prices would negatively affect on the costs and competitiveness of fossil-fuel technologies (primarily, coal-fired). However, the base-case calculations of electricity generating costs for Russia are performed and presented without CO_2 prices.

Nuclear security fund

- For Russian nuclear plants actual legislation assumes that special fund assignments (in percentage of gross revenue) must be included in operation costs. These assignments are intended for: operating waste management and disposal facilities (1.3%), ensuring nuclear, radiation, fire and technical security (3.2%), ensuring physical security and nuclear materials control (0.9%).

South Africa

ESKOM Holdings' Chief advisor on Environmental Economics, Ms Gina Downes, and Senior Advisor on Corporate Finance, Ms Luyanda Qwemesha, were invited to participate as industry experts to the EGC Expert Group. They provided cost data for two electricity generation options for South Africa, a supercritical pulverized coal-fired station and an open cycle gas turbine to this study.

Capital costs

- It should be noted that for the coal-fired plant the date of the reported cost study was mid 2006 and that these costs were under revision by the time of their inclusion in this study, and will likely be revised upwards. The average exchange rate applied is 8.2.
- Overnight costs figures include contingency for construction, and major refurbishment is estimated (and accounted for) at a fixed percentage of placed and unplaced work packages respectively, which is around 11% on average for the coal plant and 10% for the open cycle gas turbine.
- System costs were not included but ESKOM estimates that there will be significant transmission costs incurred in order to integrate these plants, as well as the construction of 2 additional substations; 6 x 765 kV transmission power lines over a distance of 460 km; as well as several shorter 400 kV transmission lines.

Load factors and lifetimes

- The open cycle gas turbine, with a total capacity of 1 050 MW for 7 units, has a real load factor of 6% although in this report 85% is assumed in order to compare costs for baseload technologies. In reality open cycle gas turbines fulfil a peaking role on the electricity national grid system. The reported plant is therefore expected to operate at a 6% load factor and for a technical life of 20 years, instead of the standard 30 years that were applied.

Fuel prices

- In the coal plant, the primary fuel is domestic sub-bituminous, high ash coal with a LHV of 17.9 GJ/tonne. The domestic coal price assumption is ZAR 120/tonne or USD 14.63/tonne.
- Fuel for the open cycle gas turbine is said to be diesel with a 48.28 LHV GJ/t. The diesel price assumption is ZAR 9.77/MBtu or USD 1.19/MBtu.

Taxes

- Although not included, there is a new levy in South Africa that was introduced from 1 July 2009 on gross electricity produced from non-renewable sources of 2c/kWh.

Environmental costs

- As for the rest of non-OECD countries, no CO_2 cost was applied. There are however in South Africa other relevant environmental protection limits.

- The National Environment Air Quality Act No. 39 of 2004 will eventually replace the whole of the Atmospheric Pollution Prevention Act No. 45 of 1965. The new Act was gazetted in Feb 2005 and certain sections of the act came into force on 11 September 2005. During the transitional phase an application for a registration certificate under the old legislation (APPA) will be taken as an application for an atmospheric emission license under the Air Quality Act. Currently, a set of ambient air quality standards has been proposed which allows for the introduction of stricter air quality standards in a phased manner. Emission limits have also been proposed in July 2009 for the various sectors of industry and these too are currently being reviewed by the relevant Standards Committee, although they are some way from finalisation. The costs for this plant include estimates for pollution control to comply with minimum emissions standards, provisionally at 50 mg/Sm^3 for particulate matter; 500 mg/Sm^3 for SO_2 and750 mg/Sm^3 for NOx.
- Following ESKOM's indications, the costs associated with flue gas desulphurisation were added to variable O&M costs.

List of abbreviations

ABWR	Advanced boiling water reactor
AC	Air-cooled
AGT	Advanced gas turbine
APR	Advanced power reactor
APWR	Advanced pressurised water reactor
ASU	Air separation unit
BioG	Biogas
BioM	Biomass
Bk	Black coal (sum of coking coal, steam coal)
Br	Brown coal (sum of sub-bituminous coal and lignite)
BRICS	Brazil, Russia, India, China and South Africa
CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CC(S)	Carbon capture where *currently* no storage is included
CERA	Cambridge Energy Research Associates
CHP	Combined heat and power
CIF	Carriage-insurance-freight
COD	Commissioning date
Com	Commercial
CPR	Chinese pressurised reactor
CSP	Concentrating solar power
DCF	Discounted cash flow

ECBM	Enhanced coal-bed methane
EGC	Electricity generating costs
EOR	Enhanced oil recovery
EPC	Engineering, procurement and construction
EPCM	Engineering, procurement, construction and management
EPR	European pressurised reactor
EPRI	Electric Power Research Institute
ESAA	Energy Supply Association of Australia
ETP	*Energy Technology Perspectives*
EU ETS	European Union Emission Trading Scheme
FBC	Fluidised bed combustion
FOAK	First of a kind
GHG	Greenhouse gas
GJ	Gigajoules
HH	Henry Hub
IDC	Interest during construction
IGCC	Integrated gasification combined cycle
Indus	Industrial
IPCC	Intergovernmental Panel on Climate Change
kW	Kilowatt
kWe	Kilowatt of electric capacity
LCOE	Levelised cost of electricity
LHV	Lower heating value
LNG	Liquefied natural gas
MIT	Massachusetts Institute of Technology
MMBtu (and MBtu)	Million British thermal units, a common unit for natural gas
MOX	Mixed-oxide fuel
MWh	Megawatt hour
NBP	National Balancing Point
NCU	National currency unit
NPV	Net present value

NSU	OECD Nuclear Sector Understanding
OCGT	Open cycle gas turbine
OPR	Optimised power reactor
O&M	Operations and maintenance
PCC	Pulverised coal combustion
PCCI	Power Capital Cost Index
PPI	(Electric Power Generation) Producer Price Index
PV	Photovoltaic
PWR	Pressurised water reactor
REN	Renewable energies
Res	Residential
SC	Supercritical
STEG	Solar thermal electricity generation
SUBC	Subcritical
TJ	Terajoules
USC	Ultra-supercritical
USD	US dollars
varRE	Variable renewable energy sources
VVER	Water-cooled and water-moderated power reactor
WACC	Weighted average cost of capital
WC	Water-cooled
WEO	*World Energy Outlook*

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