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# Reviewing electricity generation cost assessments

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# Abstract

## Reviewing electricity generation cost assessments

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Studies assessing electrical energy generation costs of various power generating technologies are becoming increasingly common and references to such studies can often be heard in the public debate. Different studies do however often present significantly different results. This is a problem as electricity generation cost assessments are important when it comes to choosing and designing future energy systems. In this thesis, existing electricity generation cost assessments are reviewed and issues and differences with current methodologies are investigated. As many of the reviewed studies lack detailed sensitivity analyses, an electricity generation cost model has been implemented in order to shed some light on the sensitivity in the produced results.

The review shows that different methodological approaches and assumptions have a significant impact on electricity generation cost results. The habit of generalising electricity generation costs in a public context can also be questioned. Generation costs tend to be site-specific and sensitive to changes in input parameters.

Another finding is that current methodologies are not suitable for comparing intermittent and dispatchable power generating technologies. The reasons are missing electricity system cost perspective and failure to account for differences in production profiles.

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# Populärvetenskaplig sammanfattning (Swedish summary)

Kostnadsanalyser för olika elenergitekniker fyller en viktig funktion när det kommer till att välja och utforma framtida energisystem. Ett stort antal elproduktionskostnadsstudier har genomförts av såväl myndigheter som företag och referenser till sådana studier är vanligt i den offentliga debatten. Ett problem är dock att studier ofta kommer fram till vitt skilda resultat.

I detta examensarbete har en kritisk granskning av olika kostnadsanalyser avseende elproduktion genomförts. Skillnader och problem med befintlig metodik identifieras och diskuteras. Kostnadsanalyser är viktiga vid värderingen av specifika projekt. I sådana sammanhang kan det även vara relevant att presentera specifika elproduktionskostnader. Dock är det vanligt att studier generaliserar elproduktionskostnader. Denna studie undersöker om ett sådant tillvägagångssätt är att rekommendera när man pratar om elproduktionskostnader för ett givet kraftslag.

Ett problem är att flertalet av de granskade studierna inte lägger någon fokus på känslighetsanalyser i sina rapporter. På detta sätt får läsare ingen uppfattning om känsligheten i de presenterade resultaten. Därför har en elproduktionskostnadsmodell implementeras med syftet att visa på känsligheten i vissa parametrar och därigenom bidra till en förståelse över varför olika studier kommer fram till så pass skilda resultat.

Granskningen visar att metodik och antaganden har en stor påverkan på de elproduktionskostnader som presenteras. Vanan att generalisera elproduktionskostnader kan också ifrågasättas. Anledningen är att elproduktionskostnader är platsspecifika och känsliga mot ändringar i ingående parametrar.

Nuvarande metoder lämpar sig inte heller för att jämföra intermittenta, väderberoende kraftslag med reglerbara alternativ. Detta på grund av att nuvarande metoder inte tar någon hänsyn till de kostnader som ett givet kraftverk har om man ser på elsystemet i sin helhet. Fokus ligger på kostnader för producenten och inte på de kostnader som möts av konsumenterna. Systemkostnader är högre för intermittenta kraftslag än för reglerbara alternativ. Det är dock mycket svårt att kvantitativt yttra sig om omfattningen av dessa kostnader då området är i behov av mer forskning.

Nuvarande metoder övervärderar dessutom intermittenta kraftslag på grund av att all el antas säljas till samma pris. I verkligheten varierar elpriset från timme till timme och skillnaderna kan vara signifikanta. Ingen hänsyn tas till att reglerbara kraftslag har en större sannolikhet att kunna producera el under de timmar på året då elpriset är som högst.

# Table of Contents

1 Introduction ........ 1
1.1 Question at issue ........ 1
1.2 Delimitations ........ 1
1.3 Method ........ 2
2 Critical review of electricity generation cost assessments ........ 3
2.1 Reviewed studies ........ 3
2.2 Included power generation technologies ........ 6
2.3 The purpose of electricity generation cost assessments ........ 7
2.4 Input data ........ 8
2.4.1 Summary of input data in the reviewed studies ........ 9
2.5 Constructed power plants, power plants under construction, or planned projects? ........ 13
2.5.1 Number of installations ........ 14
2.6 Mixing of different technologies ........ 14
2.7 General comments on input data ........ 15
2.8 Cost calculation methodology ........ 15
2.9 Common base for cost comparison and exchange rates ........ 20
2.10 Some examples of methodological differences ........ 21
2.10.1 Discount rates ........ 21
2.10.2 Fuel prices ........ 23
2.10.3 Efficiency ........ 25
2.10.4 Heat credits and gate fees ........ 27
2.10.5 Economic life ........ 29
2.10.6 Capacity factor ........ 30
2.10.7 Decommissioning costs, refurbishment costs and residual values ........ 33
2.10.8 Flue gas treatment- and ash management costs ........ 34
2.10.9 Contingency costs ........ 34
2.10.10 Carbon dioxide emission fees ........ 35
2.10.11 Total electricity system costs ........ 35
2.10.12 Backup costs ........ 36
2.10.13 Degradation ........ 37
3 Cost comparison ........ 38
3.1 Investment costs ........ 38

3.1.1 The difference between overnight- and total investment cost ................................ 38
3.1.2 Presentation of overnight investment costs ............................................................ 39
3.1.3 General comments on the investment cost figures ................................................. 40
3.2 O&M cost figures ........................................................................................................ 42
3.3 Fuel cost ....................................................................................................................... 45
3.4 Carbon dioxide emission costs ...................................................................................... 46
3.5 Backup power costs ...................................................................................................... 46
3.6 Generation costs ........................................................................................................... 47
3.6.1 Generation cost for non-renewable technologies ................................................... 47
3.6.2 Generation cost renewable technologies ................................................................ 49
3.6.3 Generation cost comparison ................................................................................... 50
4 Sensitivity analysis .......................................................................................................... 52
4.1 Sensitivity analysis in the reviewed studies ................................................................. 52
4.2 Sensitivity analysis using a LCOE model ..................................................................... 53
4.2.1 Impact of changing major cost parameters ................................................................ 54
4.2.2 Impact of changes in the discount rate ....................................................................... 63
4.2.3 Impact of changes in the capacity factor ..................................................................... 63
4.2.4 Impact of using overnight- vs. total investment cost (including the IDC) ................. 66
4.2.5 Impact of carbon emission costs ............................................................................. 66
4.2.6 Comparison of using constant vs. increasing fuel- and carbon cost ....................... 67
5 Another perspective from looking at expected revenue ....................................................... 69
5.1 Results using constant prices ........................................................................................ 72
5.2 Impact of heat price ....................................................................................................... 76
5.3 Results using increasing prices ..................................................................................... 77
5.4 Using peak prices .......................................................................................................... 80
6 Shortcomings- and improvement suggestions of existing methodologies ........................... 84
6.1 Deficiencies in existing methodologies ......................................................................... 84
6.2 Suggestions for improvements of existing methodologies ............................................ 86
6.2.1 The need for transparency ....................................................................................... 86
6.2.2 Input data ................................................................................................................. 86
6.2.3 Presentation of results .............................................................................................. 87
6.2.4 Avoid mixing of different technologies ................................................................... 87
6.2.5 Widen the system border and account for differences in production profiles ......... 87

7 Discussion ........ 90
7.1 Regional issues ........ 90
7.2 Economies of scale ........ 91
7.3 The impact of time ........ 92
7.4 Impact of system boundary ........ 93
7.5 Site-specific issues ........ 93
7.6 Comparing apples and oranges ........ 94
7.7 The impact of electricity generation cost assessments ........ 94
8 Conclusions ........ 95
9 Future work ........ 96
Acknowledgements ........ 97
References ........ 98
Appendix ........ 104
A Prepared questions for the panel debate at the RSAS ........ 104
B Number of different cases for the included power generation technologies ........ 105
C EIA discount rate projection ........ 106
D Fuel prices ........ 107
E Total investment cost in the reviewed studies ........ 113
F Levelised O&M cost ........ 120
G Levelised fuel cost ........ 121
H Total generation cost in the reviewed studies ........ 122
I Assumptions on input parameters used in the LCOE model ........ 129
J LCOE model setup (hard coal power plant) ........ 131

## List of figures

Figure 1. ALLGC formula used in the CASES (2008a) study. 16
Figure 2. LCOE formula used by IEA & NEA (2010).. 16
Figure 3. Levelised cost of produced energy in the EUSUSTEL (2007) study 17
Figure 4. Example of a levelised cost build-up (Mott MacDonald, 2010). 19
Figure 5. Brent spot price [$/barrel] (EIA, 2012b). 24
Figure 6. Henry Hub spot price [$/Mil.BTUs] (EIA, 2012c) 24
Figure 7. Back-up cost formula used by CASES (2008a) 36
Figure 8. Overnight investment cost comparison [SEK/kW$_e$]. 40
Figure 9. International capital cost indexes and Swedish price increases 41
Figure 10. EPCCI index (IHS, 2012). The lower curve excludes nuclear power plants. 42
Figure 11. Levelised O&M cost non-renewable power generating technologies 43
Figure 12. Levelised O&M cost renewables 44
Figure 13. Levelised O&M cost renewables (including the EUSUSTEL figures) 44
Figure 14. Levelised fuel cost in the reviewed studies [SEK/MWh$_e$]. 45
Figure 15. Generation cost non-renewables 48
Figure 16. Generation cost (with and without carbon emission cost) for hard coal- and CCGT-C power plants (10% DR). 48
Figure 17. Wind power and CHP-B generation cost (5% and 10% discount rate). 49
Figure 18. Hydropower and PV generation cost (5% and 10% discount rate). 50
Figure 19. Generation cost comparison at 5% DR. 50
Figure 20. Generation cost comparison at 10% DR. 51
Figure 21. Generation cost breakdown (base case). 53
Figure 22. Hard coal LCOE sensitivity analysis result 55
Figure 23. Lignite coal LCOE sensitivity analysis result 55
Figure 24. CCGT-C LCOE sensitivity analysis result 56
Figure 25. CCGT-CHP LCOE sensitivity analysis result 56
Figure 26. OCGT LCOE sensitivity analysis result 57
Figure 27. Nuclear LCOE sensitivity analysis result 57
Figure 28. CHP-B LCOE sensitivity analysis result 58
Figure 29. CHP-W LCOE sensitivity analysis result 58
Figure 30. Reservoir hydropower LCOE sensitivity analysis result 59
Figure 31. PV LCOE sensitivity analysis result 60
Figure 32. Wind power onshore LCOE sensitivity analysis result 60
Figure 33. Wind power offshore LCOE sensitivity analysis result 61
Figure 34. Generation cost impact by changes in multiple parameters. 62
Figure 35. Generation cost as a function of discount rate 63
Figure 36. Capacity factor sensitivity analysis (base-load power generating technologies) 64
Figure 37. Capacity factor sensitivity analysis (intermittent power generating technologies) 65
Figure 38. Impact on LCOE by assuming increasing fuel prices 67
Figure 39. Impact on LCOE by assuming increasing carbon emission costs 68
Figure 40. Price duration curve Nord Pool Spot 71
Figure 41. Discounted payback period hard coal (5% DR). 73
Figure 42. Price trend electricity certificates (Ekonomifakta, 2012). 74

Figure 43. Elspot prices Sweden (Nord Pool Spot, 2012)........................................................ 77
Figure 44. Nord pool hourly spot prices 24/5 2012 (Nord Pool Spot, 2012)........................... 80
Figure 45. Nord pool daily spot prices February 2012 (Nord Pool Spot, 2012)...................... 80
Figure 46. Regional LCOE differences (IEA and NEA, 2010) ............................................... 90
Figure 47. Change in the Annual Energy Outlook investment cost assumptions (EIA, 2010b) ................................................................................................................................ 92

## List of Tables

Table 1. Power generating technologies included in the reviewed studies. .............................. 7
Table 2. Number of different cases for each power generation technology. .............................. 7
Table 3. Cost calculation methodologies .................................................................. 20
Table 4. Assumed exchange rates (Riksbanken, 2012) .......................................................... 21
Table 5. Assumed discount rates [%].. ........................................................................ 22
Table 6. Fuel prices.. ........................................................................................ 24
Table 7. Assumption on heating values. ...................................................................... 26
Table 8. Efficiency assumptions in the reviewed studies [%] ................................................. 27
Table 9. Heat credit assumptions. ............................................................................ 28
Table 10. Assumed economic lifetimes.. ....................................................................... 30
Table 11. Capacity factors for non-renewable power plants .................................................. 31
Table 12. Capacity factors renewable power plants. .......................................................... 32
Table 13. Assumptions on carbon dioxide emission fees ....................................................... 35
Table 14. Length of construction period in the reviewed studies.. ........................................... 38
Table 15. Interest rate during construction [%] .............................................................. 39
Table 16. Allocation of investment cost during the construction period ..................................... 39
Table 17. O&M cost base.. .................................................................................... 43
Table 18. Levelised carbon cost [SEK/MWh$_e$]. ................................................................ 46
Table 19. Assumptions on backup cost for wind power [SEK/MWh$_e$]. ......................................... 47
Table 20. Generation cost breakdown (base case) [SEK/MWh$_e$]. .............................................. 54
Table 21. Tested parameters in the sensitivity analysis. .................................................... 54
Table 22. Generation cost impact by changes in multiple parameters [SEK/MWh$_e$]. ........................... 62
Table 23. Impact on CHP generation cost by assuming base-load vs. heating-season operation [SEK/MWh$_e$] ........................................................................................... 64
Table 24. Generation cost using overnight- vs. IDC investment cost (10% DR) .................................. 66
Table 25. Impact of changes in the carbon emission costs [10% DR] .......................................... 67
Table 26. Input parameters DCF model ......................................................................... 70
Table 27. Assumption on electricity price used in the DCF model .............................................. 71
Table 28. Economic indicators at 5% DR ....................................................................... 73
Table 29. Economic indicators at 10% DR ...................................................................... 73
Table 30. Impact of electricity certificates on the economic indicators ..................................... 75
Table 31. Impact of carbon emission costs on the economic indicators ........................................ 76
Table 32. Impact of heat price on CHP indicators ............................................................. 77
Table 33. Economic indicators at a 2% yearly price increase (5% DR). ........................................ 78
Table 34. Economic indicators at a 4% yearly price increase (5% DR).. ....................................... 78
Table 35. Economic indicators at a 2% yearly price increase (10% DR) ........................................ 79
Table 36. Economic indicators at a 4% yearly price increase (10% DR) ........................................ 79
Table 37. Economic indicators electricity market value test [5% DR] ......................................... 81
Table 38. Nuclear- and wind power plant with the same LCOE ................................................... 82
Table 39. Nuclear- and wind power economic indicators comparison ............................................ 82
Table 40. Examples of economies of scale ..................................................................... 91
Table 41. Examples of the impact of time on electricity generation costs ..................................... 93

# Abbreviations

| | |
|---|---|
| AEO | annual energy outlook |
| ALLGC | average lifetime levelised generation cost |
| APR | advanced power reactor |
| CASES | cost assessment for sustainable energy systems |
| CF | capacity factor |
| CC | coal condensing |
| CCS | carbon, capture and storage |
| CCGT-C | natural gas combined cycle condensing |
| CCGT-CHP | natural gas combined cycle combined heat and power |
| CDF | cumulative discounted cash flow |
| CHP-B | combined heat and power biomass |
| CHP-W | combined heat and power waste |
| DECC | department of energy and climate change |
| DCF | discounted cash flow |
| DPB | discounted payback period |
| DR | discount rate |
| EIA | energy information administration |
| EPR | european pressurized reactor |
| EPCCI | european power capital cost index |
| EUSUSTEL | euoropean sustainable electricity |
| EWEA | european wind energy association |
| FBC | fluidized bed combustion |
| FCF | free cash flow |
| FOAK | first of a kind |
| GDP | gross domestic product |
| HC | heat credit |
| HHV | high heating value |
| HP | hydropower |
| IDC | interest during construction |
| IQR | interquartile range |
| IEA | international energy agency |
| IMF | international monetary found |
| kWe | kilowatt electrical |
| LCA | life cycle assessment |
| LCG | levelised cost of generation |
| LCOE | levelised cost of electricity |
| LHV | low heating value |
| $MWh_e$ | megawatt hour electrical |
| $MWh_h$ | megawatt hour heat |
| NEEDS | new energy externalities development for sustainability |
| NP | nuclear power |
| NPV | net present value |
| NEA | nuclear energy agency |
| NGO | non-governmental organisation |
| O&M | operation and maintenance |
| OCGT | open cycle gas turbine |
| OECD | organisation for economic co-operation and development |
| PB | parsons brinckerhoff |

| | |
|---|---|
| PCC | pulverized coal combustion |
| PP | payback period |
| PSI | paul scherrer institute |
| PV | photovoltaic |
| PwC | pricewaterhousecoopers |
| ROR | run of river |
| SEK | svensk krona |
| SKGS | skogen, kemin, gruvorna och stålet |
| VAT | vaue added tax |
| WEO | world energy outlook |
| Wp | wind power |
| WACC | weighted average cost of capital |
| UoS | use of system charge |
| RSAS | Royal Swedish Academy of Sciences |
| ROR | run-of-river |
| LCOE | levelised cost of electricity |
| IQR | interquartile range |

# 1 Introduction

Studies focusing on the electricity generation cost[1] from different power generating technologies (such as nuclear power, wind power and biomass applications) are becoming more and more common and references to such studies can often be heard in the public debate. The topic is very sensitive due to the different opinions of how to best shift over to a new, sustainable energy system and at what cost this can be made.

Knowing the electricity generation cost is important as it affects the electricity price, something that is a part of our daily life and is a crucial factor to our electricity intensive industries. Credibly implemented electricity generation cost analyses are very important as the results are distributed to e.g. energy utilities, associations, politicians and to the general public.

A problem recognized by the Energy Committee at the Royal Swedish Academy of Sciences, and the research group Global Energy Systems at Uppsala University, is that objective and reliable electricity generation cost assessments seem rather rare. Many different studies have been carried out and there is a large spread in the reported results. Electricity generation cost analyses have an important role when it comes to choosing and designing future energy systems. This calls for an investigation of why different studies arrive at such different results (Kullander and Höök, 2011).

## 1.1 Question at issue

The main purpose of this thesis is to perform an independent investigation of different studies trying to assess the electricity generation cost of various power generating technologies. Existing electricity generation cost assessments are reviewed and issues and differences with current methodologies are identified and highlighted.

Cost analyses are important when evaluating specific projects, but is it relevant to generalise electricity generation costs from a planning and policy point of view? This thesis also focuses on this question, i.e. can electricity generation costs be generalised to the point where it is possible to state a certain electricity generation cost for a given power generating technology?

## 1.2 Delimitations

- The notion of electricity generation costs is interpreted as costs that can be directly correlated to the investment and operation of a given power plant. Costs arising from external effects on e.g. human health, climate change and wildlife are therefore not considered.
- Focus is on "pure" generation costs. Taxes and subsidies will as far as possible not be considered.

[1] A more accurate name would be *electrical energy* generation cost. E*lectricity* is the physical phenomena associated with the flow and presence of electric charges, whereas *electrical energy* is the energy provided by electricity. The use of *electricity generation costs* is however commonly accepted and it will therefore be retained in this review.

- Future estimates are not considered. Focus will be on cost figures without influence from assumptions on e.g. learning curves and other cost reductions, i.e. what it would cost to build and operate a power plant starting today.

## 1.3 Method

In order to answer the question at issue, several different electricity generation cost assessments are scrutinized and methodological differences are identified. Problems with current electricity generation cost methodologies are detected and discussed.

As many of the reviewed studies lack detailed sensitivity analyses, an electricity generation cost model is implemented in order to show the sensitivity of certain parameters and provide some explanations to why there is such a large spread in the reported results.

A set of questions have been prepared and handed out to people with insights in electricity generation cost analyses. These questions have been answered in a seminar held at the Royal Swedish Academy of Sciences and partly also in writing. The answers will be used to provide some useful opinions about the purpose and applicability of electricity generation cost assessments.

Electricity generation costs are important, but they do not provide the whole picture. The deregulation of the power markets have shifted the focus from cost minimizing to revenue maximising. Different power generating technologies displays different economic profitability as the market value of the electricity that they supply can be very different. This is an important issue that current electricity generation cost analyses fail to account for. A cash flow model has therefore been implemented in order to provide a profitability evaluation of a set of specific projects instead of only focusing on their costs.

# 2 Critical review of electricity generation cost assessments

## 2.1 Reviewed studies

**Cost Assessment for Sustainable Energy Systems**

The *Cost Assessment for Sustainable Energy Systems* (CASES) was a project funded by the European Commission under the Sixth Framework Programme[2]. The CASES project involved 26 different partners from mainly research and higher education institutions around Europe. The project started in April 2006 and lasted for a total of 30 months. One of the main objectives with the CASES study was to provide detailed estimates to stakeholders about the internal and external costs of different energy sources for countries within the EU. The cost findings have then been used to evaluate policy options for improving the efficiency of energy use within the EU (CASES, 2008b).

**El från nya och framtida anläggningar**

The study *El från nya och framtida anläggningar* is the latest report on electricity generation costs by Elforsk AB, a company owned by Svensk Energi (a non-profit industry organization for Swedish companies involved in the supply of electricity) and Svenska Kraftnät (operates and manages the Swedish grid). The purpose of the Elforsk corporation is to rationalize the research and development within the common sector of the participating companies (Elforsk, 2012). The cost calculations have been performed by independent energy consultants under supervision of a reference group with members from Elforsk and some larger energy companies. The report is dated 2011.

**European Sustainable Electricity; Comprehensive Analysis of Future European Demand and Generation of European Electricity and its Security of Supply**

The *EUSUSTEL* (abbreviation for *European Sustainable Electricity*) project started in January 2005 and lasted for 24 months. The objective was to provide the European Commission with guidelines of how to optimize the future electricity provision and electricity mix in order to achieve a sustainable electricity supply system within the EU. A part of the project consisted of summarising private and external electricity generation costs from different power generating technologies. In accordance with the CASES project, this study was also funded by the Sixth Framework Programme. A group of scientist from various European countries carried out the work through a committee, which also included stakeholders and participants from electric industries. The main work consisted of reviewing existing studies and publications, complemented by expertise from the persons involved in the project (EUSUSTEL, 2007f).

[2] A European Community Framework programme which funded and promoted research at EU level

**Investment and Operation Cost Figures – Generation Portfolio**

Author of the *Investment and Operation Cost Figures* study is VGB PowerTech e.V, a voluntary association for European companies involved in power and heat generation. The main goal of the VGB cooperation is to optimize and support the availability, economy, operational safety and environmental compatibility of existing and future power plants (VGB, 2012). The study is based on a survey among VGB's members and it was conducted in mid-2011 (VGB, 2011).

**Kostnader för ny elproduktion – en jämförelse mellan olika aktörers bedömningar**

*Kostnader för ny elproduktion – en jämförelse mellan olika aktörers bedömningar* is a study conducted by Förnybart.nu, an organisation striving to form an opinion for vigorous ventures on renewable energy and energy efficiency. The report summarises different actors estimates on electricity generation costs. Focus is on some renewable energy technologies and on nuclear power. The study was published in November 2010 (Förnybart.nu, 2010).

**Levelized cost of New Generation Sources in the Annual Energy Outlook 2011**

The study *Annual Energy Outlook 2011* (AEO2011) presents long-term projections on U.S. energy supply, demand- and prices- up to year 2035. The results are based on the U.S. Energy Information Administration's (EIA) energy-economic modelling system NEMS (EIA, 2011). The levelized electricity generation costs presented by the EIA are the ones that are configured for the AEO2011 reference case (EIA, 2010a).

Capital costs, O&M costs and the power plants heat rates were provided by an outside contractor, engineering company R.W. Beck (EIA, 2010b).

**New Energy Externalities Developments for Sustainability**

The objective of the *NEEDS* (New Energy Externalities Developments for Sustainability) project was to evaluate the full costs and benefits (direct plus external) of energy policies and of future energy systems. The project lasted for a total of 54 months and ended in February 2009. It involved a total of 66 different partners from mainly universities, research institutions, industry partners and NGOs within Europe. The NEEDS project was also funded by the European Commission under the Sixth Framework Programme (NEEDS, 2009).

Some of the NEEDS results have later been updated by researchers at the Paul Scherrer Institue (PSI) and published in a PSI magazine (PSI, 2010). This study is therefore also included in this review.

**Projected Costs of Generating Electricity**

*Projected Costs of Generating Electricity* is a recurring study by the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA). The latest study was released in 2010. The study was performed by support from an ad hoc expert group consisting of national experts, academia and industry experts. Input data have been collected through member countries governments (directly or indirectly via the ad hoc group), industrial companies and industry associations (IEA and NEA, 2010).

**Review of the generation costs and deployment potential of renewable electricity technologies in the UK / Electricity Generation Cost Model – 2011 update**

The two different studies on electrify generation costs (one for non-renewable technologies and one for renewable alternatives) mentioned in the headline above are studies conducted on request by the Department of Energy and Climate Change (DECC), a British government department created in 2008. Its priorities are to ensure a diverse, safe, secure and affordable energy system within the UK, but also to work for international actions to tackle climate change. The DECC use independent consultants to provide regular updates on electricity generation costs.

The latest independent report on electricity generation costs from non-renewable power plants is provided by consulting firm Parsons Brinckerhoff (PB, 2011). The latest update on renewable technologies was conducted by professional services firm Arup (Arup, 2011). The original study and the electricity generation cost model was created by consulting firm Mott MacDonald in 2010 (Mott MacDonald, 2010).

**Vad kostar kraften?**

The study *Vad kostar Kraften?* was ordered by SKGS, a cooperation between four Swedish trade associations regarding energy matters within the Swedish base industry. The purpose of the study was to produce a discussion basis on the question of whether nuclear power is expensive compared to other power generating technologies on the Nordic electricity market. Consulting firm PricewaterhouseCoopers (PwC) is author of the report and responsible for the cost calculations. The study was released in April 2010 (SKGS, 2012).

**Panel debate participants**

In addition to a seminar titled "Energy supply - environmental effects, risks and costs" at the RSAS, a set of questions was prepared and handed out to a selected group of people with knowledge of electricity generation cost analyses. This group of people is presented below.

- Lars Wrangensten, Elforsk AB. Responsible for program area electricity- and heat production at Elforsk AB.
- Robert Gorosch, PwC. Manager at PwC and active collaborator in the electricity generation cost study "Vad kostar kraften".
- Jessica Henryson, Westanders Klimat och Energi. Responsible for focus area Climate and Energy at Westander. Major participator in the Förnybart. nu's compilation on electricity generation costs ("Kostnader för ny elproduktion – en jämförelse mellan olika aktörers bedömningar").
- Dr. Stefan Hirschberg, PSI. Head of the Interdepartmental Laboratory for Energy Systems Analysis at the Paul Scherrer Institut (PSI), Switzerland. Major participator in the NEEDS study on electricity generation costs.
- Prof. Bent Sørensen, Roskilde University. Professor Emeritus at Roskilde University.
- Tommi Ekholm, VTT. Research scientist and PhD student at VTT Technical Research Centre of Finland.

All listed persons except Jessica Henryson and Tommi Ekhom participated in a panel debate on electricity generation cost assessments at the end of the seminar. Jessica Henryson and Tommi Ekholm have however provided their opinions in written form.

The presentation and the following debate were recorded and can be found online at kvatv.se[3]. The session is called “A Swedish perspective on cost analyses – Presentations and Q & A session”. The prepared questions can be found in Appendix A.

## 2.2 Included power generation technologies

Focus is on electricity generation costs from power generating technologies commercially interesting to implement in the Nordic electricity system. Following power generating technologies are included in this review on electricity generation cost assessments.

- Coal condensing power
- Combined heat and power using biomass fuels
- Combined heat and power using waste as fuel
- Hydropower
- Natural gas combined cycle
- Natural gas combined cycle with combined heat and power
- Natural gas open cycle
- Nuclear power
- Photovoltaics
- Wind power (onshore and offshore)

The chosen technologies were selected out of a set of different criteria’s. They should all be interesting to implement in the Nordic electricity system and they should be technically mature technologies commercially available on the market. Renewable technologies such as PV and wind power are interesting to include from a policy and an energy system transition perspective. CHP technologies are important elements in the Nordic energy system due to the cold climate. Hydropower has long been the most important electricity generation source in Norway and Sweden due to the numerous rivers in these countries. Nuclear power generates substantial amounts of electricity in Sweden and in Finland (with more to come). Fossil-fuelled technologies are important elements in Finland and Denmark’s energy systems.

Technologies that are not yet commercially available (such as stations equipped with Carbon, Capture and Storage (CCS) have not been included in this study. The investigated power generating technologies that are included in the reviewed studies are presented in Table 1.

[3] http://kva.screen9.tv/#KCIeQeWo4bPJAztezT8dsA

**Table 1.** Power generating technologies included in the reviewed studies. DECC have acquired costs data for OCGT and CCGT-CHP power plants. The generation cost of these technologies is however not provided in the report (PB, 2011). Förnybart.nu compiles a set of various electricity generation cost studies. The relevant ones have been further investigated in this report.

| Study | Considered power generating technologies | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | CC | CHP-B | CHP-W | HP | CCGT-C | CCGT-CHP | OCGT | PV | NP | WP onshore | WP offshore |
| CASES | x | x | | x | x | x | x | x | x | x | x |
| Elforsk | x | x | x | x | x | x | | x | x | x | x |
| EUSUSTEL | x | | | x | x | x | | x | x | x | x |
| Förnybart | | x | | | | | | x | x | x | x |
| IEA & NEA | x | | | | x | x | | x | x | x | x |
| NEEDS | x | x | | | x | | x | x | x | | x |
| SKGS | | | | x | | | | | x | x | |
| DECC* | x | x | x | x | x | x | x | x | x | x | x |
| EIA | x | | | x | x | | x | x | x | x | x |
| VGB | x | | | x | x | | x | x | x | x | x |

Some studies use several different cases for the same power generating technology. Examples include plants with different net electricity output or plants placed at different locations, implying different e.g. investment costs, O&M costs and assumptions on capacity factor. The notion of hydropower includes both reservoir installations and run-of-river applications. Some studies include both options, other focuses on one of the alternatives. The number of different cases for each power generating technology included in the reviewed studies can be seen in Table 2. A more thorough explanation of the different cases can be found in Appendix B.

**Table 2.** Number of different cases for each power generation technology. The IEA & NEA (2010) figures refer to their median case.

| Study | Power generating technology | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | CC | CHP-B | CHP-W | HP | CCGT-C | CCGT-CHP | OCGT | PV | NP | WP onshore | WP offshore |
| CASES | 1 | 2 | | 4 | 1 | 2 | 1 | 2 | 1 | 1 | 1 |
| Elforsk | 1 | 4 | 1 | 2 | 1 | 2 | | 1 | 1 | 3 | 2 |
| EUSUSTEL | 2 | | | 4 | 2 | 2 | | 2 | 2 | 2 | 2 |
| IEA & NEA | 1 | | | | 1 | | | 1 | 1 | 1 | |
| NEEDS | 2 | 2 | | | 1 | | 1 | 3 | 1 | | 1 |
| SKGS | | | | 3 | | | | | 6 | 3 | |
| DECC | 1 | 1 | 1 | 2 | 1 | 3 | 1 | 1 | 1 | 2 | 3 |
| EIA | 1 | | | 1 | 2 | | 2 | 1 | 1 | 1 | 1 |

## 2.3 The purpose of electricity generation cost assessments

According to DECC (2012), electricity generation costs are a fundamental part of energy market analysis and therefore important when designing policies. EIA (2010a) is on a similar track and views electricity generation costs as critical inputs when developing energy projections and energy analyses. New plant costs are also stated as being helpful when determining how new capacity competes to already existing power plants.

IEA & NEA (2010) state that their report can be used by policy makers, researchers and industry professionals whom wish to have a better understanding of the power generation cost of different technologies. VGB (2011) agrees and state that the purpose of their study is to provide policymakers, members and academia with robust order of magnitude data on investment and operation cost figures of different power plants. Elforsk (2011b) states a similar but more general purpose with their study. The overall aim is to provide the reader with a basis for cost comparison of different power generating technologies.

Henryson (2012) highlights that Sweden and other countries are in need of investments in new generating capacity the coming years. Accurate and fair cost estimates are important as the public opinion is largely affected by the perception on whether a specific technology is considered as being cheap or expensive compared to other alternatives.

Hirschberg (2012) state that electricity generation cost analyses are necessary when assessing the economics of an investment. What are actually the driving factors behind the costs? Electricity generation costs are absolutely necessary for any comparative assessments including sustainability assessments. Ekholm (2012) highlights that the purpose depend on who is doing the analysis. From a company point of view the purpose would be to maximize profits, but from the perspective of national economics the purpose would be to ensure that costly resources (such as labour and fuel) coverts into something that has higher economic value.

This short compilation shows that different studies indeed have different main purposes. What needs highlighting is the big impact that these analyses might have on policy makers and on other influential organisations/persons. The governmental organisations appear to use them in market analyses, energy projections, and when forming new policies. Big organisations such as IEA and VGB targets policymakers. This highlights the importance of electricity generation costs analyses as the produced results are likely to be important in decision-making.

## 2.4 Input data

Relevant and trustworthy data sources are necessary when performing electricity generation cost evaluations. A direct resemblance to the famous metaphor "garbage in – garbage out" (Hinde, 2004) can be made. A related problem has to do with the traceability of the used input data. From an academic point of view it is very important that you can trace the input data back to its original source. Can you trust studies where the input data sources are hidden, making it impossible to recreate the results on your own?

A general problem in the reviewed studies is the lack of trustworthy input data according to the introduction above. In many cases reliability issues occur because of the unwillingness by companies to share either the input data sources or the model used in the cost calculations. Occasionally questions arise on why certain input data are chosen and why some assumptions are made without a relevant and good explanation of the actions taken. In other instances the input data seems quite old and too out of date to fairly reflect the prevailing conditions at the time of the study. According to IEA and NEA (2010), the ongoing privatisation of utilities and the liberalisation of the power markets have reduced the access to production cost data because of the commercially sensitive nature of this subject. This might be an explanation to why studies do not share their input data sources to the readers.

Another problem is the risk of comparing apples and oranges when using input data stemming from a wide variety of different sources. This problem is also evident when comparing different studies with each other.

In the following paragraphs the investigated studies will be examined in accordance to the discussion in this section.

### 2.4.1 Summary of input data in the reviewed studies

**Cost Assessments for Sustainable Energy Systems**
Very little information regarding input data can be found in the reports. It is only stated that the input data are based on estimates by power plant manufactures, power plant operators and scientists.

**El från nya och framtida anläggningar 2011**
The investment costs are stated as mostly being based on constructed and planned facilities in Sweden and in other Nordic countries. This is true for biomass-, waste- and CCGT-CHP power plants, nuclear power and wind power. The IEA (2010) and the European Climate Foundation (2012) have been used as references for fossil-fuelled stations and other power plants not common in the Nordic countries. Data are also claimed to be collected from suppliers, from energy company contacts and from research networks. O&M costs are standard values collected from literature, statistics and calculations. Fuel prices stems from official sources (such as the Swedish Energy Agency), supplemented with data from fuel suppliers and users.

The input data sources are fairly well defined for nuclear power and for CCGT-CHP. The data on biomass- and waste CHP are stated to originate in constructed facilities in Sweden and in Scandinavia, but the sources are not explicitly given. For hydropower the data sources are a mix of international investigations and inputs from energy producing companies and other Elforsk studies. The data used for wind power plants are not referenced at all.

**European Sustainable Electricity; Comprehensive Analysis of Future European Demand and Generation of European Electricity and its Security of Supply**
Comments about the different power generating technologies and the correlated input data are provided in different work packages (reports).

The report on coal-fired power plants mostly deals with technical aspects. The cost figures are provided in accompanying appendixes (EUSUSTEL, 2007b, EUSUSTEL, 2007c). However, when comparing these figures with the ones provided in one of the main synthesis reports (EUSUSTEL, 2007h), discrepancies exist. Statements on plant size, investment cost and O&M cost for lignite-fuelled plants are not the same in the report as in the appendix. The cost data for lignite power plants also lack references (EUSUSTEL, 2007e).

The cost figures for CCGT stations stems from two different sources, one stated as an internal source and the other as the IEA. For CCGT-CHP, both technical and economic data have been retrieved by choosing figures from a few of the power plants included in the IEA study *projected costs of generating electricity 2005 update* (the prequel to the study included in this study).

For wind power, the provided investment cost figure is not the same in the work package (EUSUSTEL, 2007l) as in the main reports (EUSUSTEL, EUSUSTEL, 2007e, EUSUSTEL, 2007h). Neither the technical nor the economic data sources for nuclear power can be found in the related work package (EUSUSTEL, 2007j) or in the appendix (EUSUSTEL, 2007c).

The investment cost for reservoir hydropower is based on an American source (Idaho National Laboratory, 2005). The reference is a website which in turn lacks references to the presented cost figures. The authors of the work package also state that the costs are subject to U.S. taxation and that they therefore are not directly applicable to European conditions. EUSUSTEL still seem to use these figures without any recalculations. The O&M cost figures given in the appendix (EUSUSTEL, 2007a) are not the same as the ones provided in the workpackage (EUSUSTEL, 2007g). The cost figures for ROR hydro are stated to be based on an IEA 2003 report. The investment cost figure presented in the work package (EUSUSTEL, 2007g) is however not the same as the one provided in the main report (EUSUSTEL, 2007e).

The origin of the cost data for PV plants is unknown.

**Investment and Operation Cost Figures – Generation Portfolio**
Very few comments regarding input data can be found in the report. The investment- and O&M cost sources are stated as “the major players in Europe, on both the generation and the supply side” (VGB, 2011).

**Kostnader för ny elproduktion – en jämförelse mellan olika aktörers bedömningar**
The main studies referenced in the Förnybart.nu report are presented below.

- Wind power

European Wind Energy Association - *The Economics of Wind Energy (EWEA, 2009)*.
International Energy Agency - *World Energy Outlook* 2009 (IEA, 2009).
Elforsk - *El från nya anläggningar 2007* (Elforsk, 2007)

- PV

International Energy Agency - *Technology Roadmap. Solar photovoltaic energy* (IEA, 2010b)

- Nuclear power.

Citi - *Nuclear–The Economics Say No* (Citi, 2009). Econ Pöyry - *Framtidens Energilösningar: Effekter av Energipolitiska vägval* (Pöyry, 2008)

- CHP – B

Elforsk - *El från nya anläggningar 2007 (Elforsk, 2007)*

No focus will be placed on the Elforsk study *El från nya anläggningar 2007* as its sequel *El från nya och framtida anläggningar 2011* is a part of this study. Econ Pöyry (providing cost calculations on nuclear power) relies completely on estimated investment costs for a reactor presently under construction in Flamanville (France). This project is currently four years behind schedule and costs have risen by approximately a factor two. The delay is due to e.g. accidents at the site and the need of more analyses because of the Fukushima accident (Nuclear Engineering International, 2011). The Econ Pöyry study is therefore excluded from this study.

The IEA study *World Energy Outlook* is a recurring publication on global long-term energy market analysis. The information on the electricity generation costs presented in the 2009 update is very scarce. The methodology used in the cost calculations is unknown and no information regarding input data is provided in the report. The source is stated as "IEA analysis" and the only cost figures provided are the investment costs and the generation cost results. The information provide in the IEA study *Technology Roadmap. Solar photovoltaic energy* is also very scarce. The only comment is that the input data are based on IEA internal sources.

EWEA (2009) presents generation cost figures for windpower (onshore and offshore) in their 2009 study *The Economics of Wind Energy***.** Investment cost data for onshore applications are provided by the IEA (based on limited European installations). The O&M cost figures are based on existing turbines. For offshore wind power, investment costs are based on a set of European wind farm installations (mainly located in Denmark and in the UK). The O&M cost is an assumed figure.

Citi (2009) use information from a few different suppliers (supplemented with some literature sources) to estimate the investment cost for nuclear power plants. No statement regarding the O&M- and fuel cost source is provided. The methodology used when calculating the generation cost is not mentioned in the report.

**Levelized cost of New Generation Sources in the Annual Energy Outlook 2011**
The data sources are not provided in the report. An EIA employee (Martin, 2012) states that R.W. Beck has access to a variety of cost data on different power plants. They also possess significant experience from consulting on power plant projects. Much of the cost data are however proprietary. Fuel prices are provided by the EIA.

**New Energy Externalities Development for Sustainability**
The various power generating technologies have been investigated by different NEEDS participants. The data sources are a mix of references to e.g. existing power plants, manufacturers and various reports. Technical- and economic cost data are taken from different sources. It is sometimes difficult to understand which data that has been used. Many sources are stated in the reports but it is not always explicitly stated which ones that have been used.

Hard coal power plant data are based on existing and planned facilities in Denmark and in Germany. The cost data on lignite power plants comes from some major electrical appliances manufacturers. Technical data for the lignite power plant are also based on a German installation. The cost data for CCGT power plants and simple gas turbines seem to stem from personal communication with a major electrical appliances manufacturer. The technical parameters are based on an existing German installation and on general information (NEEDS, 2008b). The technical parameters are taken from a LCA study investigating a wind farm located in Denmark. Cost data are based on another Danish wind farm installation. Note that NEEDS only look at offshore wind power.

The cost data for PV systems seem to be based on studies by a European industry association and a major European electricity company. Technical data appears to be taken from the IEA.

For biomass power plants, technical data are based on three different literature sources. No reference to the cost data can be found in the report. Data regarding nuclear power are taken from a study by the French department of energy and natural resources dated 1997. Even though this seems as a legit source, it is old and therefore maybe outdated.

Nothing is stated about the input data sources used when calculating the updated NEEDS cost figures (PSI, 2010). According to Hirschberg (2012), detailed analyses are behind the cost calculations. The sources are however confidential due to arrangements with PSI clients and because that most of the results are not yet published.

Something worth noticing when it comes to the NEEDS study is that the present day (2007) generation cost figures are not provided in any report. The ingoing cost parameters (e.g. investment costs and O&M cost) and future electricity generation cost estimates are stated in different reports, but present day generation cost figures are missing. The reason for this is unknown. The generation cost figures used in this study are taken from a presentation held at the final NEEDS conference (NEEDS, 2009b). The generation costs are only presented in a poorly scaled graph and some alternatives are also missing.

**Projected Costs of Generating Electricity 2010 Edition**
The input data are stated to be based on current experience, published studies and on industry surveys. The data have been received through member countries governments, either directly or indirectly via the ad hoc expert group. Data are also provided by industrial companies and industry associations.

**Review of the generation costs and deployment potential of renewable electricity technologies in the UK / Electricity Generation Cost Model – 2011 update**

- **Non-renewable technologies**

The information provided is very scarce due to confidentiality issues. The cost data is claimed to mainly stem from reference power plants. Where such power plants were unavailable, estimates drawn from other studies and from the experience of PB technology experts were used as cost sources. O&M cost data are in many cases taken from another PB study on electricity generation costs (PB, 2010). The DECC has provided the data on fuel-, waste disposal- and decommissioning costs (PB, 2011). Their sources are not stated in the report.

- **Renewable technologies**

The input cost data are taken from publicly available information (mainly industry reports), proprietary data from Arup and Ernst&Young (which helped with the cost data gathering), and from consultation with industry stakeholders. The stakeholders (a total of 70 contributors, mainly developers and facility owners) provided information on recently completed projects or projects that are in construction or under development. The fuel cost data stems from the DECC (Arup, 2011). As for the non-renewable technologies, the cost data information is on a very general level and not much more detailed than what is stated above.

**Vad kostar kraften?**

Data regarding wind power are mostly stated to be based on PwC's own experience from wind power projects. The availability and the residual value of the wind power turbines are assumed figures.

The investment cost for nuclear power plants is based on a report by Citi (2009), while the O&M cost are taken from existing Swedish nuclear power plants. Assumptions are made regarding financing issues, availability, station size and residual value.

For hydropower the investment- and the O&M cost originates in interviews with some larger energy producing companies. These companies have also provided information regarding the availability of Swedish hydropower plants. Financing data are claimed to be based on PwC's own experience from similar projects.

## 2.5 Constructed power plants, power plants under construction, or planned projects?

An observation is that the reviewed studies seldom put a lot of effort in explaining whether the input data stems from existing power plants, power plants under construction, planned projects, or something else. This is remarkable as it clearly is a big difference between using data that are measured or known to data that is estimated.

VGB (2011) explicitly state that the assumptions on both investment- and O&M costs are based on real projects and the corresponding operational data. It is however not possible to deduce whether this is the case for all power generating technologies or if VGB actually distinguishes between constructed power plants and projects under construction.

IEA and NEA (2010) do not explicitly state which of the different headline categories that the input data are based on. Data on Chinese power plants are stated to be based on projects currently under construction. This kind of information is however not provided for the other power plants included in the study. The same problem also exist in the Elforsk (2011b) study. Some of the power generating technologies are stated to be based on a mix of constructed and planned stations (although unknown to which extent). In other cases the subject is not mentioned.

The DECC studies (Arup, 2011, PB, 2011) seem to be using a mix of existing power plants and projects currently under construction. This is at least true for renewable power sources, where stakeholders are claimed to have provided data on either recently completed projects, power plants under construction, or projects currently in development. Benchmarks for proposed projects have also been used. The information provided on non-renewable technologies is scarcer.

Due to the general lack of information on input data in the CASES (2008a) study, it is simply not possible to deduce if the input data stems from constructed power plants or on other sources. The same goes for the World Energy Outlook (IEA, 2009) and the PV roadmap (IEA, 2010b) studies. The input data in the EWEA (2009) study seems to be based on wind farms constructed in Europe. This is definitely true for offshore wind installations, while for onshore wind power this is more on an indicative level.

The input data used in the NEEDS study stems from a large variety of different sources. In some cases the input data seems to be based on constructed power plants, while in other cases the data stems from electrical appliances manufacturers or from literature sources (NEEDS, 2009a).

Information on input data sources in the EUSUSTEL (2007e) study is scarce. It is very hard to deduce if the data are based on figures from real projects or on something else.

### 2.5.1 Number of installations

It is interestingly to know whether the cost figures are based on single or on multiple data points, e.g. a single power plant vs. multiple installations of the same power generating technology. In this way a better understanding of the extent of the input data and also an indicator of how site specific the cost figures could be is provided.

IEA & NEA (2010) provides a good example of this topic. The total number of power plants included for each power generating technology is explicitly given in the report and cost figures are provided for each individual power plant. This study do however seem to be the exception that proves the rule as no other study presents the number of data points in this way. EWEA (2009) includes the number of data point for wind power offshore installations but not for onshore turbines. An example of how IEA & NEA (2010) presents their data points can be found in Appendix B.

## 2.6 Mixing of different technologies

A problem is that some studies do not differentiate between different power generating technologies. An example is to combine crystalline silicon solar cells with thin film alternatives and naming them “photovoltaics”. Another example is to combine different types of nuclear reactors and just naming them “nuclear power”. This approach can be questioned.

In many cases it is hard to deduce if this approach has been used because of the general lack of information regarding input data (Elforsk, 2011b, CASES, 2008a, VGB, 2011). As for the DECC studies (Arup, 2011, PB, 2011), this seems to be a problem for some technologies such as PV and nuclear power. EUSUSTEL (2007i) also seem to mix various silicon- and thin film PV technologies.

In the IEA and NEA (2010) study, generation costs are presented for each individual power plant, but results are also stated by using a combined figure for six main categories (nuclear, coal, coal with CCS, CCGT, wind onshore and PV).  For nuclear power the combined result seem to be a mix of different technologies such as EPR and APR reactors. The coal category is a mix of different technologies such as PCC and FBC power plants. Different CCGT technologies also seem to be mixed. This circumstance should be kept in mind when looking at the generation cost figures presented in the IEA & NEA (2010) median case.

Other examples are different PV applications (rooftop vs. open-space installations), single- or multiple installations at the same site (for e.g. nuclear- and coal power plants), and assuming brownfield or greenfield[4] conditions. It is difficult to estimate the impact of these peculiarities, but there is an evident risk of comparing apples and oranges when looking at cost figures from different studies.

## 2.7 General comments on input data

A general observation it that investment- and O&M cost figures stated in the reports are very hard to scrutinize. The reason for this is the general adopted methodology of presenting costs without separating the different components. How can cost be compared or understood if they only are presented as lumped figures? R.W. Beck (EIA, 2010b) is an exception and separates the different investment cost components into a few different cost categories. The same approach is not used for O&M costs and the breakdown is not detailed or carefully explained, but it is nevertheless an example of how different cost components could be distinguished, thereby making it more relevant to compare different studies with each other and also to understand why there is such a large spread in the reported cost figures.

It is also worth commenting that it is common to use different sources for technical and economic input data. For instance, technical parameters might be based on literature sources, while the economic data is gathered from real projects or from manufacturers. The different data categories have therefore no direct correlation to each other. The reason for choosing different sources is not known, but one possible explanation might be that technical data is more abundant and more easily accessible than cost data. It difficult to estimate the impact of this peculiarity, but it is evident that it should affect the results somehow.

Another general problem more or less common to all reviewed studies is the lack of transparency in the reports. The input data sources are in most cases hidden and therefore also untraceable. Some studies have been contacted regarding this matter, but none have upon request been able to share their input data sources. The cost formulas and models are in many cases hidden and/or their function poorly explained, making it hard and cumbersome to understand the calculations. Assumptions are sometimes never explained or clearly motivated. Some studies only present cost figures and make few to no comments on the steps taken to come up with these results. These circumstances make it hard to estimate the relevance of the produced result, thereby forming a credibility issue.

## 2.8 Cost calculation methodology

The most common method of calculating electricity generation costs seems to be the general levelised cost of electricity (LCOE) methodology. It is a discounted cash flow (DCF) approach where all cost streams (e.g. capital-, O&M- and fuel costs) and the expected electricity output are converted to equal annual payments by using present values. It is simply

[4] Brownfield sites are abandoned or underused facilities available for re-use. A greenfield land is unused and has no existing infrastructure

the ratio of the net present value of total lifetime power plant costs to the net present value of the (net) electricity generated by that plant over its operating life. The generation costs are calculated on basis of net power supplied to the power station busbar[5] (CASES, 2008a, IEA and NEA, 2010).

Some other associated names for the general LCOE methodology seems to be Average Lifetime Levelised Generation Costs (ALGC), Levelised Costs of Energy (also abbreviated LCOE) or Levelised Cost of Generation (LCG).

The LCOE formula used by CASES (2008a) is presented in Figure 1, while Figure 2 shows the formula used by IEA & NEA (2010).

$$ALLGC = \frac{\sum_{t=0}^{T} \frac{\left[I_t + M_t + F_t\right]}{(1+r)^t}}{\sum_{t=0}^{T} \frac{\left[E_t\right]}{(1+d)^t}}$$

| | |
|---|---|
| $I_t$ | = Investment expenditures in year t |
| $M_t$ | = Operation and Maintenance expenditure in year t |
| $F_t$ | = Fuel expenditures in year t |
| $E_t$ | = Electricity generation in year t |
| r | = Discount rate |
| ALLGC | = Average Lifetime Levelised Generating Costs ( $\bar{p}$ ) |

**Figure 1.** ALLGC formula used in the CASES (2008a) study. The symbol “d” is probably a misprint. It should be interpreted as “r”, i.e. the discount rate.

| | |
|---|---|
| $Electricity_t$: | 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”. |

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

From (1) follows that

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

which is, of course, equivalent to

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

**Figure 2.** LCOE formula used by IEA & NEA (2010). For combined heat and power plants, a heat credit is subtracted from total unit costs to establish an equivalent of the levelised costs of producing only electricity.

[5] Where electricity is fed onto the grid

These formulas essentially say the same thing. The decommissioning expenses are a part of the investment cost in the CASES (2008a) report and IEA & NEA (2010) also account for carbon emission costs (standard value). The formula used in the EUSUSTEL (2007e) study is provided in Figure 3.

$$c_{ene} = d \cdot \frac{c_{inv}}{E} + c_{fuel} + c_{oem} \qquad (1)$$

where

| | |
|---|---|
| $c_{fuel}$ | fuel cost |
| $c_{inv}$ | investment cost |
| $c_{oem}$ | operation and maintenance cost |
| E | net yearly electricity production |
| d | discount factor (d) |

The discount factor d is defined by the effective interest rate (r) and the life-time of the investment ($t_{life}$):

$$d = \frac{1-(1+r)^{-t_{life}}}{r} \qquad (2)$$

**Figure 3.** Levelised cost of produced energy in the EUSUSTEL (2007) study

This formula is harder to interpret. For example, it is not stated whether the O&M- and the fuel cost should be taken on a yearly basis or not. Neither is it obvious that these costs have to be divided by the net yearly electricity production (in order to make sense of the dimensions). It also seems as the equation rather should be divided by the discount factor then multiplied by it (as Figure 3 indicates). This can cause a lot of confusion. However, by looking at a presentation from the half year meeting of the EUSUSTEL project (EUSUSTEL, 2006), it was confirmed that they actually use the same approach as CASES (the Figure 1 formula appears in the presentation).

Elforsk (2011b) calculates the electricity generation cost by using a spreadsheet model. The capital costs are calculated by using the equivalent annual cost (EAC) method and the O&M – and fuel costs are assumed as constant in time. The Elforsk methodology and the LCOE approach seem to yield similar results if all variable costs, such as O&M and fuel costs, are assumed as constant in time, all other assumptions being equal. VGB (2011) seems to be using a similar approach as Elforsk. The investment costs have been calculated by using the EAC method while the O&M cost is stated as an annual percentage of the investment cost. How the fuel- and carbon costs are calculated is unknown. Something worth noticing is that VGB also name their generation cost figures as “levelised cost of electricity (LCOE)”.

The methodologies used by SKGS (PwC, 2010) and EIA (2010a) seem to be different from the ones discussed so far. SKGS (PwC, 2010) claims to be using a methodology called Free Cash Flow (FCF). Little information is provided in the report, but the methodology seems to be dealing with depreciation, amortization and other factors not mentioned by PwC in the report (Investopedia, 2012c). This can however not be confirmed as the methodology is poorly explained and because that the cost model is unavailable to the readers. It is therefore difficult to deduce how they actually calculate the electricity generation costs. The EIA (2010a) use an energy-economic model called NEMS to calculate the electricity generation costs (referred to as "levelized cost"). Levelized costs are described as the present value of the lifetime costs and the plant utilization rate, converted to equal annual payments. This approach sounds similar to the LCOE methodologies described above, although substantial differences between the various cases exist. The NEMS model use both inputs and other unknown variables to compute the levelized costs. The model is very complex, results cannot be recreated offline and the calculations are not based on a single formula (Martin, 2012).

The approach used in the NEEDS study is difficult to understand. Communication with NEEDS participants has revealed that the generation costs were estimated through an extensive analysis, but that costs were also generated with an energy-economic model called TIMES. However, there were large discrepancies between these costs, why they were harmonized by NEEDS participants (in an unknown way). The subject gets more confusing as NEEDS lack a report that summarises the findings and the results. The only present-day cost figures that can be found are located in a presentation held at the final NEEDS conference (NEEDS, 2009b). However, these costs have only been prepared in order to demonstrate the usefulness of social and external costs (Preiss, 2012). In this case the ALLGC methodology was used, indicating that this probably is the approach used in the NEEDS study. It is confusing that only future generation cost figures are presented in a report while present day generation costs missing. Email correspondence (Preiss, 2012, Hirschberg, 2012) have also revealed that caution when looking at generation cost figures presented in the NEEDS project is recommended. The study was more focused on external costs and the generation cost figures have later been updated in a subsequent study made by researchers at PSI (Hirschberg, 2012). The information provided on this study is scarce and it is not stated which methodology that has been used in the cost calculations (PSI, 2010).

EWEA (2009) and IEA (2010b) seem to be using levelised cost approaches similar to IEA & NEA (2010). The approach used by Citi (2009) and IEA (2009) is unknown.

The DECC studies (Arup, 2011; PB, 2011) uses an approach which at a first glance seems very similar to the LCOE methodology used by e.g CASES (2008a) and IEA & NEA (2010). The DECC electricity generation cost model was developed by consulting firm Mott Mcdonald in 2010 (Mott MacDonald, 2010). This model (with updated cost assumptions and technical input data) has also been used in the latest studies. The model calculates the "levelised cost of electricity generation (LGC)". Figure 4 shows an example of a hypothetical LGC build-up in the Mott Mcdonald (2010) study. This figure will be used to highlight some possible differences between the reviewed studies. The word "possible" is used as no other reviewed study includes a similar example of a generation cost build-up. Elforsk (2011b) provides their model which makes some comparisons possible. The other studies are discussed on basis of the provided formulas and on the methodology descriptions given in the reports.

Table 4.1: Example of levelised cost build-up for hypothetical power plant

| | Un-discounted values | | | | | | Discounted values | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Capex: £m | Opex: £m | Fuel: £m | Total costs: £m | TWh output | Discount factor (based on a 10% d.r.) | Capex : £m | Opex: £m | Fuel: £m | Total costs: £m | TWh output |
| 2009 | | | | | | 1.000 | | | | | 0 |
| 2010 | | | | | | 0.909 | | | | | 0 |
| 2011 | 50 | | | 50.0 | | 0.826 | 41.3 | 0 | 0 | 41.3 | 0 |
| 2012 | 200 | | | 200.0 | | 0.751 | 150.3 | 0 | 0 | 150.3 | 0 |
| 2013 | 400 | | | 400.0 | | 0.683 | 273.2 | 0 | 0 | 273.2 | 0 |
| 2014 | 250 | | | 250.0 | | 0.621 | 155.2 | 0 | 0 | 155.2 | 0 |
| 2015 | 100 | | | 100.0 | | 0.564 | 56.4 | 0 | 0 | 56.4 | 0 |
| 2016 | | 25 | 175.2 | 200.2 | 4.4 | 0.513 | 0 | 12.8 | 89.9 | 102.7 | 2.2 |
| 2017 | | 25 | 297.8 | 322.8 | 7.4 | 0.467 | 0 | 11.7 | 138.9 | 150.6 | 3.5 |
| 2018 | | 25 | 297.8 | 322.8 | 7.4 | 0.424 | 0 | 10.6 | 126.3 | 136.9 | 3.2 |
| 2019 | | 25 | 297.8 | 322.8 | 7.4 | 0.386 | 0 | 9.6 | 114.8 | 124.5 | 2.9 |
| 2020 | | 25 | 297.8 | 322.8 | 7.4 | 0.350 | 0 | 8.8 | 104.4 | 113.2 | 2.6 |
| 2021 | | 25 | 297.8 | 322.8 | 7.4 | 0.319 | 0 | 8.0 | 94.9 | 102.9 | 2.4 |
| 2022 | | 25 | 297.8 | 322.8 | 7.4 | 0.290 | 0 | 7.2 | 86.3 | 93.5 | 2.2 |
| 2023 | | 25 | 297.8 | 322.8 | 7.4 | 0.263 | 0 | 6.6 | 78.4 | 85.0 | 2.0 |
| 2024 | | 25 | 297.8 | 322.8 | 7.4 | 0.239 | 0 | 6.0 | 71.3 | 77.3 | 1.8 |
| 2025 | | 25 | 297.8 | 322.8 | 7.4 | 0.218 | 0 | 5.4 | 64.8 | 70.3 | 1.6 |
| 2026 | | 25 | 297.8 | 322.8 | 7.4 | 0.198 | 0 | 4.9 | 58.9 | 63.9 | 1.5 |
| 2027 | | 25 | 297.8 | 322.8 | 7.4 | 0.180 | 0 | 4.5 | 53.6 | 58.1 | 1.3 |
| 2028 | | 25 | 297.8 | 322.8 | 7.4 | 0.164 | 0 | 4.1 | 48.7 | 52.8 | 1.2 |
| 2029 | | 25 | 297.8 | 322.8 | 7.4 | 0.149 | 0 | 3.7 | 44.3 | 48.0 | 1.1 |
| 2030 | | 25 | 297.8 | 322.8 | 7.4 | 0.135 | 0 | 3.4 | 40.2 | 43.6 | 1.0 |
| 2031 | | 25 | 280.3 | 305.3 | 7.0 | 0.123 | 0 | 3.1 | 34.4 | 37.5 | 0.9 |
| 2032 | | 25 | 262.8 | 287.8 | 6.6 | 0.112 | 0 | 2.8 | 29.3 | 32.1 | 0.7 |
| 2033 | | 25 | 245.3 | 270.3 | 6.1 | 0.102 | 0 | 2.5 | 24.9 | 27.4 | 0.6 |
| 2034 | | 25 | 227.8 | 252.8 | 5.7 | 0.092 | 0 | 2.3 | 21.0 | 23.3 | 0.5 |
| 2035 | | 25 | 210.2 | 235.2 | 5.3 | 0.084 | 0 | 2.1 | 17.6 | 19.7 | 0.4 |
| Totals | 1000 | 500 | 5571.4 | 7071.4 | 139.3 | | 676.5 | 120.1 | 1343.2 | 2140 | 33.6 |
| Levelised cost in £/MWh | | | | | | | | | | | 63.7 |

**Figure 4.** Example of a levelised cost build-up (Mott MacDonald, 2010).

As Figure 4 shows, the DECC studies seem to account for a pre-development period (no cost outlay), a construction period (capital cost outlay, Capex) and an operating period. The first year of the pre-development period is chosen as basis for discounting. The other studies seem to choose the first year of operation as basis for discounting (investment costs are then discounted backwards in time). The inclusion of a pre-development period (included in the discounting period) also seem unique to the DECC studies. The output of the hypothetical power plant is not constant during all years of operation, something that seems to contradict the assumption in most other studies. More methodological differences will be discussed later on.

Note that some of the differences mentioned in the paragraphs above (such as the use of a pre-development period, different output and base year of discounting) are hard to verify because of the lack of calculation examples in the other reports. This once again highlights the problem with lack of transparency in the reviewed studies. The different methodologies chosen for cost analysis in the reviewed studies are summarised in Table 3.

**Table 3.** Cost calculation methodologies.

| Study | Methodology |
|---|---|
| IEA & NEA (2010) | levelised costs of electricity (LCOE) |
| CASES (2008) | Average Lifetime Levelised Generating Cost |
| EUSUSTEL (2007) | Average Lifetime Levelised Generating Cost |
| Elforsk (2011) | equivalent annual cost |
| SKGS (2010) | Free Cash Flow (FCF) model |
| DECC (2011) | Levelised Cost of Generation (LGC) |
| NEEDS (2009) | Average Lifetime Levelised Generating Cost |
| Updated NEEDS (Energiespiegel) (2010) | Unknown |
| EIA (2010) | levelized cost (model) |
| IEA PV Roadmap (2010) | levelised electricity generation cost |
| EWEA (2009) | levelised cost |
| Citi (2009) | unknown |
| IEA World Energy Outlook (2009) | unknown |
| VGB (2011) | levelised costs of electricity (equivalent annual cost) |

This section has so far showed some indications that methodological differences exists. In some cases, such as when comparing EIA (2010a) with CASES (2008a) and IEA & NEA (2010), differences are quite distinct. However, even between studies that seem to use very similar methodologies (such as IEA & NEA (2010), CASES (2008a) and DECC (Mott MacDonald, 2010) differences do exist. These differences will be highlighted in coming sections.

Something that causes confusion is that most studies use the word "levelised cost" (or something similar) to describe their methodology. It is important to understand that the actions taken when calculating the levelised costs might be very different from study to study, even if the terminology might indicate something else.

## 2.9 Common base for cost comparison and exchange rates

To be able to compare costs analyses conducted at different times, a common base for cost comparison is needed. In this study, all cost figures will be stated in 2011 Swedish krona. Cost figures originating in foregoing years have been recalculated to 2011 values by using a GDP deflator[6] provided by the IMF (2012).

When comparing studies from different countries (or regions), a common currency facilitates the cost comparison. Average 2011 exchange rates provided by Sveriges Riksbank, the Swedish central bank, will be used in this study. The assumed exchange rates are presented in Table 4.

[6] A GDP deflator measures the ratio of nominal (current price) GDP to real GDP, thereby indicating the inflation (or deflation) in the economy.

**Table 4.** Assumed exchange rates (Riksbanken, 2012).

| Currency | Assumed exchange rates |
|---|---|
| EUR | 9.03 EUR/SEK |
| GBP | 10.41 GBP/SEK |
| USD | 6.50 USD/SEK |

It should be noted that studies using another currency than SEK are common in this review. The assumption on exchange has therefore a large impact on the presented costs. Conversion errors due to the fact that the reviewed studies also might gather cost data from countries using other currencies will be ignored.

## 2.10 Some examples of methodological differences

Previous sections have shown some indicators on that methodological differences might be substantial. Sørensen's (2012) opinion is that this is not a problem as long as you explain what you are doing. There might be very good reasons why different studies use different approaches. Decision makers should always consider why studies use different approaches and take notes on what assumptions that leads to which results.

Gorosch (2012) state that different methodological approaches is a problem when it comes to how electricity generation cost figures are presented in media. It is important to receive a background on what methodologies that have been used and which assumptions that have been inserted into the used models. The information spread in media has a big impact on the public and on the decision makers that the studies might be directed to.

Different methodological approaches and assumptions might therefore be justified. However, such differences are important to keep in mind as they are borne to affect the presented results and because that people in general might not be aware of the big impact of using different approaches.

### 2.10.1 Discount rates

Discount rates are used to determine the present value of future cash flows. The theory is that money available today is worth more than money received in the future. The discount rate should also incorporate the uncertainty in the investment, since future cash flows might be less than expected (Investopedia, 2012a). The choice of discount rate depends on a number of factors. Two examples include the perceived risk in the investment, and perhaps the most important aspect, who the investor (determines the required return) in the project is. In any event, the discount rate is a crucial parameter when considering electricity generation costs.

It is therefore interesting that the choice of discount rate often seems very arbitrarily chosen. Many of the reviewed studies use two different discount rates without any deeper explanation of the choices made. On the other hand, VGB (2011), SKGS (PwC, 2010), with one exception, and DECC (Arup, 2011, PB, 2011), only use one discount rate without any explanation of this particular choice. It is hard to state whether one approach is better than the other.

In all but a few exceptions, the discount rates are assumed as equal for all investigated power generating technologies, implying that the risk faced by an investor is equal regardless of the project in question. SKGS (PwC, 2010) makes an exception for nuclear power which is viewed as a high risk investment. Here, two different cases with different discount rates are chosen.

SKGS (PwC, 2010), Citi (2009) and EIA (Martin, 2012) are the only studies that use a weighted average cost of capital (WACC) when calculating the discount rate. This makes it possible to account for the specific level of debt and equity financing in a project, but it also requires an assumption on corporate tax rate (Investopedia, 2012f). EIA (Martin, 2012) is the only study that uses a discount rate which varies in time. All other studies assume constant discount rates. Table 5 summarises the assumptions on discount rates in the reviewed studies.

**Table 5.** Assumed discount rates [%].The cost of equity and debt varies with time in the EIA study. See Appendix C for the complete projection.

| Study | Discount rate | WACC | Equity ratio | Cost of equity | Cost of debt | Corporate tax |
|---|---|---|---|---|---|---|
| IEA & NEA | 5 & 10 | no | - | - | - | - |
| CASES | 5 & 10 | no | - | - | - | - |
| EUSUSTEL | 5 & 10 | no | - | - | - | - |
| Elforsk | 6 & 10 | no | - | - | - | - |
| SKGS | 5.58 (8.46) | yes | 30 (50) | 10 (12.5) | 5 (6) | 26.3 |
| DECC | 10 | no | - | - | - | - |
| EWEA | 7,5 | no | - | - | - | - |
| VGB | 10 | no | - | - | - | - |
| NEEDS | 5 | no | - | - | - | - |
| Citi | 8.5 | yes | 50 | 12.5 | 4.5 (post-tax) | ? |
| Energiespiegel | 6 | no | - | - | - | - |
| IEA PV Roadmap | 10 | no | - | - | - | - |
| EIA | - | yes | 55 | Varies | | 38 |

It is obvious that there is little to no agreement on which discount rate to use. Should constant or variable discount rates be used? Should calculations be conducted by using a specific discount rate or by using multiple alternatives? Should the discount rate be 5,6 or maybe 10%? The studies provide no definite answers to these questions. Using a specific discount rate imply a high level of certainty, something that is applicable when looking at specific projects but that can be questioned in general terms. However, using two different discount rates imply that both cases are equally true. These problems might not be that evident to all readers and it also leaves an opening to use generation cost results in an uncritical way.

The issues discussed above are important to consider when looking at electricity generation cost figures. Since it is evident that in the real world the discount rate would differ from project to project, depending on e.g. who is the investor and the power plant considered, caution when talking about general generation cost figures solely due to this specific factor is therefore highly recommended.

### 2.10.2 Fuel prices

The assumptions on fuel prices are an important factor since the generation cost of some power generating technologies (e.g. gas-fired power stations) is heavily fuel dependent. Most power generating technologies except renewables (excluding biomass-fuelled power plants) use some kind of fuel to generate electricity.

IEA & NEA (2010) assume fuel prices to be constant in time. Hard coal and natural gas figures are based on average OECD import prices. The source is the IEA Office of the Chief Economist (it is not known whether the prices are based on e.g. a single case or on a time series). Brown coal is not traded internationally and hence national assumptions were used where possible. Elforsk (2011b) also assume fuel prices to be constant in time. Data is taken from both official sources (such as the Swedish Energy Agency and Statistics Sweden) and from fuel suppliers and users.

CASES (2008a) assume variable fuel prices (prices that fluctuates in time) and collect their data from the EUSUSTEL (2007e) study and from a report by the IEA (2008). Where EUSUSTEL collects their data is unknown since the stated prices lack references. Neither do the reported price figures (EUSUSTEL, 2007e) match the ones in the related work package (EUSUSTEL, 2007j). EIA (Martin, 2012), NEEDS (Hirschberg, 2012) and DECC (2011a) also use variable fuel price assumptions in their studies. The NEEDS fuel prices are stated to be based on “various sources” (Hirschberg, 2012). Fuel price projections can only be located for the fossil fuels in the EIA (2012a) and in the DECC (2011a) studies. VGB (2011) provides no figures on fuel prices in their report.

For nuclear power, studies tend to allocate the cost of the entire nuclear fuel cycle (from front-end (mining, milling, conversion, fuel enrichment and fabrication) to back-end (spent fuel transport, storage, reprocessing and disposal)) to the fuel cost (Elforsk allocates the backend costs to the O&M cost category).

The fuel price assumptions are summarised in Table 6. Most studies appear to use plant level fuel prices. The NEEDS figures are however import prices (to which to add the delivery cost in order to arrive at the final consumer price). It is not known whether NEEDS account for these extra delivery expenses or not. Complete fuel price projections for the studies that assume variable fuel prices can be located in Appendix D.

**Table 6.** Fuel prices. Elforsk assumes that the price on natural gas is dependent on the size of the power plant (larger net output -> lower price). The biomass fuel is assumed as wood residual in the CASES study and as branches and tops (GROT) in the Elforsk study.

| Study | Fuel price assumption [SEK/MWhf] | | | | | |
|---|---|---|---|---|---|---|
| | Natural gas | Hard coal | Lignite | Nuclear fuel | Biomass | Waste |
| IEA & NEA | 266 | 88 | - | 63 [SEK/MWhe] | - | - |
| Elforsk | 250-440 | 90 | - | 40 [SEK/MWhe] | 210 | -120 |
| CASES | alternating | increasing | 35 | 22 | 143 | - |
| DECC | alternating | alternating | - | - | - | - |
| EIA | alternating | alternating | - | - | - | - |
| EUSUSTEL | alternating | increasing | 35 | 29 | 132 | - |
| NEEDS | increasing | alternating | alternating | ? | 140 | - |
| Energiespiegel | Unknown | | | | | |
| VGB | Unknown | | | | | |

Assuming constant fuel prices is not necessarily wrong. An assumption on increasing fuel prices could, however, just as well be justified. This can be exemplified by Figure 5 and Figure 6.

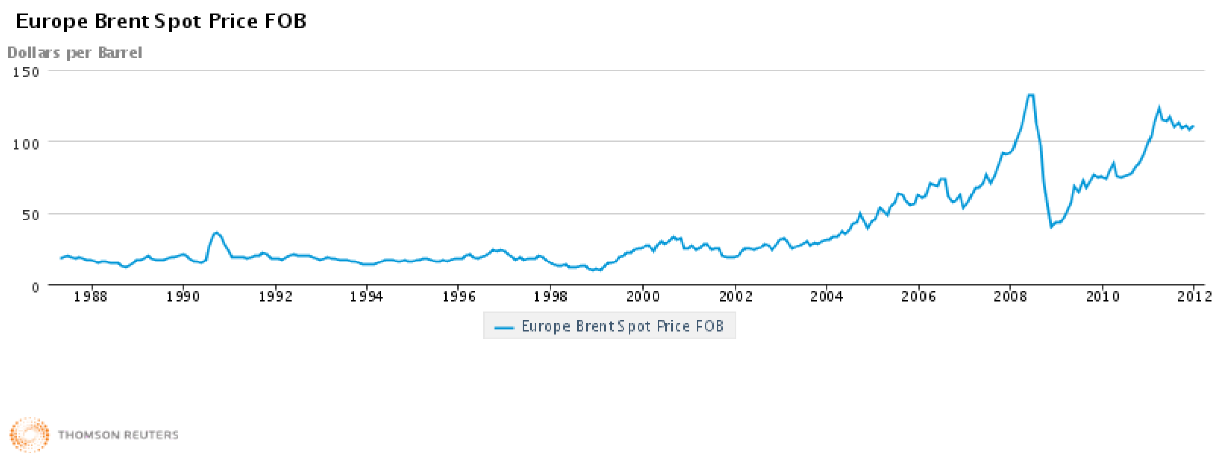


**Figure 5.** Brent spot price [$/barrel] (EIA, 2012b).

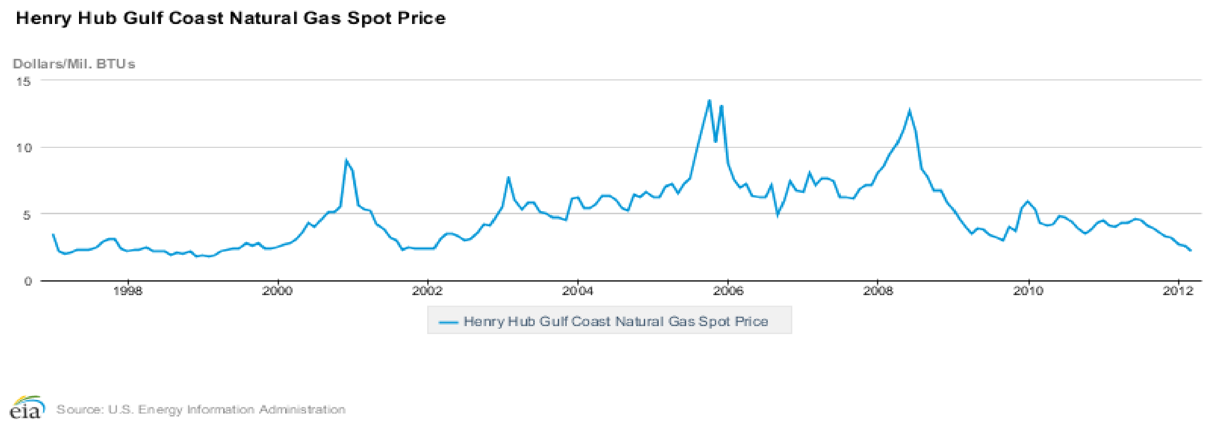


**Figure 6.** Henry Hub spot price [$/Mil.BTUs] (EIA, 2012c).

Figure 5 shows the monthly average Brent oil spot price (in real dollars). The price has clearly increased during the last decade. Figure 6 shows the variable nature of the natural gas price indicator Henry Hub (spot) during the same period. A constant fuel price assumption can therefore be questioned. On the other hand, future fuel price prognoses should be subject to a great deal of uncertainty, something that speaks for a constant fuel price assumption.

Another important factor is the assumption on fuel energy content. Some fuels, such as coal and biomass, are heterogeneous and they therefore display a large variety in the energy content on a mass basis (Coal Geology, 2010). Moreover, the average energy content of coal in a given area might decrease over time. For example, the average calorific value of U.S. coals has decreased by roughly 20% between 1950 and 2007, as the production moved to coal with lower energy content (Höök and Aleklett, 2009).

As Table 6 and Appendix D shows, large discrepancies between the reviewed studies exist. Some studies use constant fuel prices while others assume that fuel prices are increasing or varying with time. Some studies use constant prices for some fuels but increasing prices for others. In some cases the fuel prices are not stated in the reports. These differences are bound to have an impact on the generation cost result. The impact on the electricity generation cost by assuming constant vs. increasing fuel prices will be tested in the sensitivity analysis chapter.

### 2.10.3 Efficiency

The assumed efficiency affects the total fuel cost. A lower electrical efficiency leads to more fuel being spent per unit of electricity produced. The total thermal efficiency of a CHP station is also very important as it affects the amount of heat being produced in the power plant.

Something that needs considering when looking at the reported efficiency figures is if they are reported by using lower heating values (LHV) or by using higher heating values (HHV). HHV assumes that the water is in liquid state (and thereby containing the energy of vaporization) after the combustion. LHV assumes water in gas state. As the efficiency is calculated by taking the ratio of energy output to energy input, the reported efficiency will be higher by using LHV as the input on a LHV basis is smaller than when using HHV. The difference between the two values is not that high for coal power plants, but quite significant for gas-fired power plants (about 10% difference) (National Petroleum Council, 2007). Most of the reviewed studies do not mention which base they use.

IEA & NEA (2010) state that they as far as possible use national assumptions regarding the calorific value of coal. The assumed average heating value is based on IEA and OECD energy statistics. Elforsk (2011b) and NEEDS (2009a) seem to be the only studies that state the assumed heating value of all used fuels. The data sources for this are, however, unknown. DECC (Arup, 2011, PB, 2011) provide heating values for some fuels but not for all. The figures assumed by EIA are uncertain (see Table 7).

The assumptions on heating values are summarised in Table 7. It shows that many of the reviewed studies do not state which heating value they use or which heating value figure that they assume.

**Table 7.** Assumption on heating values. The calorific values assumed by EIA are stated in the report (EIA, 2010b). It is however not known if these values are the ones used within the NEMS model.

| Study | Heating values provided? | LHV | HHV |
|---|---|---|---|
| IEA & NEA | yes | x | |
| EIA | yes | | x |
| DECC | for some fuels | x | |
| CASES | no | Unknown | |
| EUSUSTEL | no | Unknown | |
| Elforsk | yes | Unknown | |
| VGB | no | Unknown | |
| NEEDS | yes | Unknown | |

The efficiency assumptions are summarised in Table 8. It clearly shows that discrepancies exist. The large difference between the EIA values and the other figures can partly be explained by EIA using HHV. The differences do however seem to be too high to only be dependent on this factor. Elforsk (2011b) and NEEDS (2009a) state that they assume best-of-a-kind technologies, something that explains the high efficiency assumptions in those studies.

**Table 8.** Efficiency assumptions in the reviewed studies [%]. Observe that Elforsk (2011b) state efficiency figures over 100% for some of their CHP plants. This is due to the combination of using efficiency figures based on LHV and flue-gas condensation (which makes it possible to use the heat released in the condensation of water).

| Technology | Electrical efficiency | Technology | Electrical efficiency | Thermal efficiency |
|---|---|---|---|---|
| **Hard coal** | | **OCGT** | | |
| IEA & NEA, min | 45 | CASES | 38 | |
| IEA & NEA, max | 46 | VGB | 45 | |
| CASES | 46 | EIA, conv | 31.5 | |
| EUSUSTEL | 48 | EIA, adv | 35 | |
| | | NEEDS | 38 | |
| Elforsk | 46 | **CCGT-CHP** | | |
| VGB | 45 | Elforsk, 150 MW | 50.5 | 92 |
| EIA* | 38.8 | Elforsk, 40 MW | 46.2 | 90 |
| NEEDS | 46 | CASES | 45 | 89 |
| DECC | 44 | **Nuclear** | | 90 |
| **Lignite** | | IEA & NEA, median | 33 | |
| IEA & NEA, min | 40 | Elforsk | 36 | |
| IEA & NEA, max | 45 | EUSUSTEL, min | 36 | |
| CASES | 44.5 | EUSUSTEL, max | 34 | |
| EUSUSTEL | 44.5 | VGB | 36 | |
| VGB | 43 | **CHP-B** | | |
| NEEDS | 45 | Elforsk, 80 MW | 30.9 | 108 |
| **CCGT-C** | | Elforsk, 30 MW | 29.2 | 107 |
| IEA & NEA, median | 57 | Elforsk, 10 MW | 26.5 | 96 |
| IEA & NEA, min | 55 | CASES | 19.5 | 69.6 |
| IEA & NEA, max | 60 | NEEDS | 20 | 65 |
| Elforsk | 58 | DECC | 18.5 | |
| CASES | 57.5 | **CHP-W** | | |
| EUSUSTEL, min | 60 | Elforsk | 19.4 | 99 |
| EUSUSTEL, max | 55 | DECC | 19.2 | |
| VGB | 60 | | | |
| DECC | 58 | | | |
| EIA, conv | 48.4 | | | |
| EIA, adv | 53 | | | |
| NEEDS | 57.5 | | | |

## 2.10.4 Heat credits and gate fees

Combined heat and power plants produces both electrical energy and heat. The costs borne by a CHP plant could therefore be imputed to both the produced electrical energy and to the produced heat. Singling out the cost shares is however difficult as electricity and heat are common products that are produced at the same time. The accepted methodology is therefore to calculate the electricity generation cost by subtracting an assumed value of the heat that is produced, which is called *heat credits*. The heat credits vary widely from study to study and the assumptions have a big impact on the generation cost result.

According to CASES (2008a), the most common way to account for heat credits is to assume that the produced heat replaces heat output from some other type of heat producing technology (usually assumed as a boiler plant). The heat credit should therefore be equivalent to the cost of the fuel that otherwise would have been consumed in the alternative boiler plant. CASES use a natural gas boiler with an assumed efficiency of 88% as the alternative heat generating plant.

Elforsk (2011b) state that regardless the site specific situation, a heat credit equivalent to the variable district heating costs can always be motivated. The heat credit is calculated by accounting for fuel usage as well as variable O&M cost for the alternative heat producing plants. These are assumed as being either a bio-fuelled- (for larger facilities), or a pellet-fuelled boiler plant (for smaller facilities (<2 $MW_{el}$)). The boilers have approximately the same net heat output as the CHP plants under consideration. However, Elforsk also account for heat credits based on fixed O&M costs and new capacity. This is true when existing, uneconomical facilities are shut down due to the introduction of the new CHP plant and when new heat capacity is needed in a given system. Fixed O&M costs such as personal expenditures can therefore be reduced and the construction cost of the new CHP facility can be reduced by the investment cost of the alternative boiler plant.

DECC (Arup, 2011) base their heat credits on avoided gas boiler costs. It is however hard to understand the methodological approach. Avoided capital- and O&M costs are stated to be based on a heat incentive by the DECC (DECC, 2011b) and the avoided fuel- and carbon costs are based on DECC gas- and carbon price projections. However, the heat incentive seem to be a fixed tariff rate, and where the generation costs are presented (Arup, 2011), heat revenues appear as a negative fixed operating cost, which is confusing.

IEA and NEA (2010) use a very simple approach by assuming a fixed heat credit per MWh of heat produced. EUSUSTEL does not mention the concept of heat credits in their main reports (EUSUSTEL, 2007f; i). Despite this, they still account for heat credits in their cost calculation appendixes (EUSUSTEL, 2007e; d) without referring to a source. It is therefore uncertain whether EUSUSTEL account for heat credits or not. The assumptions on heat credits in the reviewed studies are summarised in Table 9.

**Table 9.** Heat credit assumptions. The presented Elforsk (2011b) figure is based on variable O&M cost and avoided fuel cost (the lowest heat credit assumption).

| Study | Alternative heat production | Heat credit [SEK/$MWh_h$] |
|---|---|---|
| CASES | Gas boiler (cost of fuel) | ? |
| DECC | Gas boiler (cost of fuel, cost of carbon, O&M cost, investment) | ? |
| Elforsk | Biomass boiler (variable O&M and fuel + fixed O&M and investment) | 239 |
| IEA & NEA | Fixed value | 304 |
| EUSUSTEL | ? | ? |

It is evident that various studies treat heat credits very differently. A great deal of caution when looking at CHP generation cost figures is therefore recommended. It is also an indicator on that the topic is subject to a great deal of uncertainty. Elforsk (2011b) points to the interesting fact that lower electrical efficiency leads to more heat being produced (and hence the heat credit goes up). This might result in very low generation cost figures for CHP-B- and CHP-W plants as these facilities tend to have a quite low electrical efficiency but a high overall thermal efficiency.

A gate fee is the charge imposed on a given quantity of waste delivered to a waste processing facility. Elforsk (2011b) and DECC (Arup, 2011) are the only reviewed studies that treat waste power plants (in terms of waste CHP). The gate fee in the Elforsk study is assumed to be 360 SEK/tonne gross, where gross means that the fee also includes unsuitable waste which later is removed. The cost for the unused waste is allocated to variable O&M costs. The gate fee is stated as an average value for all of Sweden (no source provided). Arup (2011) state that the DECC use a British study (Wrap, 2011) as source for the gate fee assumption. The gate fee is stated to be taken from the lower end of the presented gate fee range (range is 885-1297 SEK/tonne for current market estimates). The data on CHP-W plants are scarce in this study, but the gate fee varies substantially between the two applicable studies. This indicates that the topic is subject to a great deal of uncertainty or/and that gate fees are very site or country specific. The gate fee assumption is a crucial factor to the generation cost from CHP-W plants.

### 2.10.5 Economic life

The economic life is the period during which the power plant is assumed to be useful to the owner. It can be different from the actual technical life of the power plant (the time period that it is physically possible to operate the installation). Many of the reviewed studies make no distinction between the different definitions.

CASES (2008a), NEEDS (2009) and EUSUSTEL (2007e) only state the technical life of the power plants. IEA & NEA (2010), DECC (Arup, 2011, PB, 2010) and VGB (2011) only use the word “lifetime”. Hence it is assumed that the technical life is equal to the economic life in these studies. Elforsk (2011b) state the assumed economic life but not the technical life of the power plants. SKGS (PwC, 2010) assumes that the economic life is equal to the assumed technical life of the power plant. EIA (Martin, 2012) assume an economic life (stated as “recovery period”) of 30 years for all power plants. This approach is unique to the EIA study. The assumptions on economic life are summarised in Table 10.

**Table 10.** Assumed economic lifetimes**.** CASES use a lifetime of 70 years for run-of-river (ROR) hydropower and 120 years for reservoir hydropower. VGB states a lifetime between 50-60 years for ROR hydro. EUSUSTEL use a lifetime of 30 years for hard coal condensing plants and 35 years for lignite condensing plants. EUSUSTEL also states a lifetime between 20-30 years for natural gas CCGT (unknown which figure they use). For hydropower, EUSUSTEL use a lifetime of 40 years for ROR plants and 50+ (also unknown if this means 50 years in the calculations or not) years for reservoir hydropower.

| Study | Economic Lifetime | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | NP | HP | CHP-B | CHP-W | CC | CCGT-C | CCGT-CHP | OCGT | WP on | WP off | PV |
| IEA & NEA | 60 | 80 | - | - | 40 | 30 | 30? | 30 | 25 | 25 | 25 |
| CASES | 40 | 70/120 | 30 | - | 35 | 35 | 35 | 35 | 20 | 20 | 25 |
| EUSUSTEL | 60 | 40/50 | - | - | 30/35 | 20-30 | 30 | - | 20 | 20 | 40 |
| Elforsk | 40 | 40 | 25 | 25 | - | 25 | 25 | - | 20 | 20 | 15 |
| SKGS | 40 | 40 | - | - | - | - | - | - | 20 | - | - |
| DECC | 40 | 41 | 25 | 29 | 35 | 30 | 15 | 40 | 24 | 24 | 25 |
| EWEA | - | - | - | - | - | - | - | - | 20 | 20 | - |
| IEA, WEO | | | | | Not stated | | | | | | |
| IEA, PV Roadmap | - | - | - | - | - | - | - | - | - | - | 25 |
| NEEDS | 40 | - | - | - | 35 | 25 | 15 | 25 | - | 20 | - |
| Citi | Not stated | - | - | - | - | - | - | - | - | - | - |
| Energiespiegel | | | | | Not stated | | | | | | |
| VGB | 40 | 50-60 | 30 | - | 35 | 25 | - | 25 | 25 | 25 | 25 |
| EIA | | | | | 30* | | | | | | |

## 2.10.6 Capacity factor

The capacity factor is an easy theoretical way of describing the output of a power plant by assuming that all production occurs at rated power during a certain period of time. It is defined as the ratio of the actual energy produced to its theoretical maximum. It is essential to make a good assumption regarding the capacity factor since it is directly correlated to the annual electricity production of the power station in question.

The capacity factors in the Elforsk (2011b) study are stated to be based on different assumptions. The capacity factor for nuclear power is based on historical data from Swedish nuclear power plants. CHP plants are assumed to only be running during the heating season. Waste CHP is an exception since these facilities have to accept waste during all seasons and the high investment cost raises the need for a high capacity factor. The capacity factor for wind power plants is stated as being equal to placing the turbines at sites where the average annual wind speed at hub height equals between 6,5-7,5 m/s for onshore wind power plants and between 8,5-9,0 m/s for offshore turbines. The capacity factor for fossil-fuelled power plants is stated to reflect conditions at continental Europe. The assumption on hydropower is not explained in the report.

IEA & NEA (2010) state that they use a standard capacity factor (0.85) for all base load power plants and country specific values for renewables. VGB (2011) also assume baseload capacity factors. They are however also stated as “determined by market conditions”. SKGS

(PwC, 2010) base their assumptions on interviews with energy utilities (hydropower) and on official statistics (wind power). The capacity factor for nuclear power is not clearly motivated.

In the EUSUSTEL (2007e) study, the capacity factors stated in the work packages (EUSUSTEL, 2007j) are not the same as those used in the cost calculations (EUSUSTEL, 2007j). This causes confusion and makes it hard to deduce where the figures stem from.

The fossil-fuelled power plants considered in NEEDS seems to be assumed as running in either base- or in peakload operation (NEEDS, 2008b). The assumed capacity factor for wind power offshore is based on an existing Danish wind farm. The CHP-B value is based on literature. The capacity factors used when calculating the updated NEEDS costs (PSI, 2010) are unknown.

**Table 11.** Capacity factors for non-renewable power plants.

| Study | Capacity factor | | | | |
|---|---|---|---|---|---|
| | NP | CC | CCGT-C | CCGT-CHP | OCGT |
| IEA & NEA, min | 0.85 | 0.85 | 0.85 | 0.85 | - |
| IEA & NEA, max | 0.85 | 0.85 | 0.85 | 0.85 | - |
| IEA & NEA, med | 0.85 | 0.85 | 0.85 | - | - |
| CASES | 0.86 | 0.86 | 0.86 | 0.86 | 0.86 |
| EUSUSTEL | 0.90 | 0.85 | 0.90 | 0.85 | - |
| Elforsk | 0.87 | 0.78 | 0.78 | 0.56 | - |
| SKGS | 0.90 | - | - | - | - |
| DECC | 0.87 | 0.95 | 0.93 | 0.93 | 0.18 |
| EWEA | - | - | - | - | - |
| NEEDS | 0.84 | - | 0.82 | - | 0.57 |
| EIA | 0.90 | 0.85 | 0.87 | - | 0.30 |
| VGB | 0.90 | 0.86 | 0.68 | - | 0.68 |

Table 11 shows that the assumed capacity factors for nuclear power, coal and CCGT-C are fairly homogenous. Some outliers such as the DECC figures on coal and CCGT-C, the VGB figure on CCGT-C and the Elforsk figures on coal and CCGT-C can be seen. The general picture is that these facilities are assumed to operate in baseload generation. The Elforsk figure on CCGT-CHP is quite different than the other assumptions. Elforsk assume that CHP plants only operate during the heating season, while the other studies seem to assume baseload operation. Large differences also exist for OCGT plants. CASES seem to assume baseload operation (unknown why) while DECC and EIA clearly assumes a peaking behaviour. The other studies assume capacity factors in the intermediate operation range.

**Table 12.** Capacity factors renewable power plants. CASES assumes a capacity factor of 0.34 for reservoir hydro and 0.57 for ROR hydro. EUSUSTEL use two cases for reservoir hydro (0.8-0.91 capacity factor) and two cases for ROR hydro (0.57-0.8 capacity factor). EUSUSTEL also use two cases for wind power onshore and wind power offshore. VGB use two different cases for wind power offshore. Elforsk use three different cases for onshore wind and two cases for offshore wind. DECC use two different assumptions for onshore wind. The VGB figure on hydro is for an ROR installation.

| Study | Capacity factor | | | | | |
|---|---|---|---|---|---|---|
| | HP | CHP-B | CHP-W | WP on | WP off | PV |
| IEA & NEA, min | - | - | - | 0.25 | 0.37 | 0.23 |
| IEA & NEA, max | - | - | - | 0.23 | 0.37 | 0.10 |
| IEA & NEA, med | - | - | - | 0.26 | - | 0.13 |
| CASES | 0.34-0.57 | 0.86 | - | 0.30 | 0.46 | 0.12 |
| EUSUSTEL | 0.57-0.91 | - | - | 0.23-0.29 | 0.29-0.5 | 0.15 |
| Elforsk | 0.46 | 0.55 | 0.76 | 0.3-0.35 | 0.34-0.35 | 0.12 |
| SKGS | 0.46 | - | - | 0.26 | - | - |
| DECC | 0.46 | 0.77 | 0.83 | 0.25-0.29 | 0.38 | 0.11 |
| EWEA | - | - | - | 0.17-0.33 | 0.41-0.42 | - |
| NEEDS | - | 0.91 | - | - | 0.46 | - |
| EIA | 0.52 | - | - | 0.34 | 0.34 | 0.25 |
| VGB | 0.80 | - | - | 0.21 | 0.37-0.43 | 0.23 |

Table 12 shows large differences on the assumed capacity factor for renewable technologies. It is interestingly to note that EUSUSTEL assumes baseload operation for reservoir hydro while all other studies assume peak- or intermediate operation. Capacity factors for wind power plants and PV installations also exhibit a large spread. These capacity factors tend to be very site specific, something that might explain the large spread in the assumptions. It is important to be aware of these differences as the assumption on capacity factor for intermittent technologies has a significant impact on the generation cost result. As the capacity factors are site specific, an assumption on a general capacity factor for these technologies can be questioned.

Something worth mentioning is that the capacity factors are mostly based on assumptions and less frequently on actual production data. This approach is not necessarily wrong if the purpose is to show how a power plant performs at different locations or in different operating modes. The problem is that many of the reviewed studies assume general capacity factors, while in reality they would change depending on geographical location and other circumstances. Using general capacity factors is therefore questionable, especially for intermittent power generating technologies. What one ought to do is to show how the power plant performs at different capacity factors, at least if the results are to be used in a public context. Boccard (2009) discuss the interesting discrepancy between estimated wind power capacity factors and average measured values. Capacity factors for wind power plants are commonly assumed to be in the 0.3-0.35 range. However, the mean realized value for European installation between 2003-2007 is 0.21. The same figure for Sweden is 0.22. This is an interesting result and it shows that stated capacity factors should not be taken for granted.

### 2.10.7 Decommissioning costs, refurbishment costs and residual values

When it is no longer economically motivated to operate a power plant it has to be decommissioned. This means that the power plant has to be dismantled, the components have to be taken care of and the site needs to be restored. One option is that the components have some form of residual value, e.g. metal scrap value or the possibility of using existing infrastructure or fundaments when building a new power plant at the same site. Refurbishing or replacing of major components might be needed sometime during a power plants lifetime.

Elforsk (2011b) account for decommissioning costs of nuclear power plants but not for other power generating technologies. IEA & NEA (2010) assumes that decommissioning costs amounts to 15% of the initial construction cost for nuclear power plants and to 5% of the construction cost for all other technologies. Country-specific data has however been used when possible. Interestingly, none of the participating countries reported any residual value even though it was possible to do so.

CASES (2008a) use a specific demolition cost for nuclear-, coal- and gas-fired power plants, but none for hydropower plants and wind power turbines. It is very hard to deduce whether EUSUSTEL account for decommissioning costs or not. One of the main reports (EUSUSTEL, 2007h) indicate that decommissioning costs are included for nuclear- and gas-fired power plants. No decommissioning costs are singled out which makes it very hard to deduce whether these are accounted for or not. Residual values are not mentioned. VGB (2011) does not mention decommissioning costs or residual values in their report.

DECC (Arup, 2011, PB, 2010, PB) accounts for decommissioning costs of nuclear power plants. For the other power generating technologies, decommissioning costs are assumed to be offset by the residual value of the power plants and refurbishment is not mentioned. NEEDS (2008b) account for decommissioning costs but no indicators on refurbishment- or residual value assumptions can be located in the reports. The approach used in Energiespiegel (the updated NEEDS figures) (PSI, 2010) is unknown.

SKGS (PwC, 2010) is the only study that assumes residual value of the power plants. The impact on the final generation cost result is however unknown. Decommissioning costs are assumed for nuclear power plants but not for the other alternatives.

Refurbishment or reinvestment costs are acknowledged by some of the reviewed studies. VGB (2011) states that they have singled out refurbishment and lifetime extension cost in their analysis. No such figures can however be located in the report. This makes it impossible to know the magnitude of these costs and which power plants that are affected. Elforsk assumes a reinvestment cost for nuclear power plants but not for other facilities. CASES (2008a), EUSUSTEL (2007h) and IEA & NEA (2010) all state that they account for refurbishment costs, but they do no not provide any actual cost figures.

A cost that occurs far away in the future will become relatively small once discounted to its present value, even if the cost considered is considerably large. The decommissioning costs in the IEA and NEA (2010) study only contributes to about 0-1% of the total generation cost and can be seen as negligible. The same thing is observed in the Elforsk (2011b) study.

Decommissioning costs (and refurbishment costs) will therefore have little to no impact on an investment decision if you use a present value approach. Nevertheless, decommissioning might take time and cost a lot of money once it takes place.

### 2.10.8 Flue gas treatment- and ash management costs

Flue gas contains a number of pollutants such as particulates, sulphur oxides, nitrogen oxides and carbon monoxide. At combustion power plants the flue gas is often treated with scrubbers and chemical processes in order to prevent the pollutants from reaching the atmosphere. Fabric filters and electrostatic precipitators remove particulates, flue-gas desulphurization removes the sulphur dioxide and nitrogen oxides can be transformed into nitrogen gas in catalytic reactions. Fly ash refers to the fine particles that rise with the flue gases, whereas bottom ash is the non-combustible residue left in the bottom or on the walls of the furnace (Alvarez, 2003). Both type of ashes needs to be removed from the facilities and deposited in some ways. Both the flue gas treatment equipment and the ash deposition will bring about extra costs for the power plant owners.

Elforsk (2011b) state that variable O&M costs increase with the ash content of fuels and if chemicals and other additives are needed for flue gas treatment. Fly ash and other flue gas treatment products are assumed to be deposited at a cost of 1200 SEK/tonne. Bottom ash is removed at an unspecified lower cost. For the coal-fired power plant plaster from flue gas scrubbers and high quality fly ash from electrostatic filters are stated to be removed via established channels without any costs. The other studies are less transparent when it comes to costs related to ash management and flue gas treatment. The techniques might be mentioned but explicitly stated cost figures are rare.

EIA (2010b) include flue gas treatment costs in the total O&M costs. Handling of ashes is however not mentioned in the report. IEA & NEA (2010) include ash management in the O&M cost. VGB (2011) and CASES (2008a) does not mention the concept of flue gas treatment and ash handling in their reports. EUSUSTEL (2007h) discuss flue gas treatment and ash handling in the report, but costs for these processes are not mentioned. The same issue arise in the NEEDS (2009a) study where the concept is mentioned but costs are not.

This section is another good example of the problem with lack of transparency in the reviewed studies. Are for instance capital costs for flue gas treatment and ash deposition costs accounted for or not? The concept of flue gas treatment and ash management is not mentioned in some studies. Other studies mention the concept but not the costs. Studies explicitly stating that they account for ash handling costs do not single out the actual cost figures which make comparison and estimation of relevance difficult.

### 2.10.9 Contingency costs

According to IEA and NEA (2010), contingencies are cost increases due to unforeseen technical or regulatory problems that might arise during the construction of a power plant. Such costs are included in the last year of construction. National data on contingencies were used when possible. If not, contingencies were assumed as 15% of the investment cost for nuclear- and offshore wind power plants, and 5% of the investment cost for all other power generating technologies. Higher contingencies for nuclear power and offshore wind power are motivated by the fact that such constructions will to some extent be first of a kind (FOAK) projects.

The 2010 DECC study on electricity generation costs (Mott MacDonald, 2010) account for both contingencies and FOAK premiums for new technologies (such as nuclear power and wind power offshore). The extra costs for FOAK projects are due to risk premiums, contingencies and unallocated over-runs. Mature technologies are also subject to contingencies, however to a much lesser extent. This methodology has been adopted in the updated report on non-renewable technologies (PB, 2011). As for the updated report on renewables (Arup, 2011), it is uncertain if extra costs have been allocated to FOAK technologies or not.

No other study seems to account for (or mentions the concept of) contingency costs and FOAK premiums.

### 2.10.10 Carbon dioxide emission fees

Some studies account for carbon dioxide emission fees that penalize power generating technologies burning fossil fuels. The fee is assumed as a specific cost per tonne of carbon dioxide released into the atmosphere. The final cost should therefore be directly correlated to the carbon content of the fuel and to the electrical efficiency of the power plant under consideration. Some studies also account for carbon dioxide damages in form of external effects (e.g. climate change), but as external costs are omitted from this study, these costs will not be considered in this thesis.

**Table 13.** Assumptions on carbon dioxide emission fees.

| Study | SEK/tonne $CO_2$ |
|---|---|
| VGB | 271 |
| DECC | 142 |
| IEA & NEA | 203 |
| EUSUSTEL | 99 |

Table 13 shows that the topic is subject to a great deal of uncertainty. There is a huge spread in the assumptions and many studies do not account for specific carbon emission costs.

### 2.10.11 Total electricity system costs

None of the reviewed studies try to account for total electricity system costs (such as transmission-, distribution-, grid connection-, reserve- and backup costs). The generation costs are in most cases plant level, meaning that the system boundary is placed at the location where electricity is fed to the grid. A few studies account for some electricity system costs such as grid connection- and backup costs. These assumptions are discussed below.

CASES (2008a), NEEDS (2009b) and EUSUSTEL (2007e) assumes that intermittent technologies are subject to backup power costs (explained in the next section), and Elforsk (2011b) and the DECC (Arup, 2011, PB, 2011) studies account for grid connection costs.

Elforsk use a standard grid connection cost but acknowledges that the cost is very site-specific and that it can account for up to 20% of the total investment cost for wind power offshore installations. The DECC studies use a different approach and assumes that grid connection is a fixed yearly operating cost. DECC also include a use-of-system (UoS) charge in the cost calculations. The UoS charge is stated as the cost charged upon an owner in order to get the required energy to the station gate (Mott MacDonald, 2010).

The fact that electricity generation costs are more or less plant level is something that needs a lot of consideration. As no study try to account for total electricity system costs, there is no point in talking about “levelised electricity costs” (or something similar) that imply a complete system consideration. A naming convention such as “electricity *generation* costs” is recommended if system costs are not accounted for. A better explanation of the impact of choosing different system boundaries is highly needed in all of the reviewed studies.

### 2.10.12 Backup costs

Some studies argue that intermittent (non-dispatchable) power generating technologies (such as wind power and photovoltaic’s) should be subject to backup costs due to their fluctuating electricity production. Backup power is needed because of the inflexible, variable and also unpredictable behaviour of these technologies.

Studies that account for backup costs are CASES (2008a), NEEDS (2009b) and EUSUSTEL (2007h). EUSUSTEL account for backup costs in the cost calculation appendixes (EUSUSTEL, 2007j), but the figures cannot be located in the main reports (EUSUSTEL, 2007e, 2007h). EUSUSTEL and NEEDS do not provide the formula they use when calculating the backup costs. This makes it impossible to deduce how the backup costs are accounted for. Interestingly enough, EUSUSTEL also assume that large scale reservoir hydro should be subject to backup costs (EUSUSTEL, 2007j). The reason for this is unknown.

Figure 7 shows the backup cost formula used by CASES (2008a). The backup power is assumed to be delivered by either a hard coal- or a CCGT power plant (same assumption is made in the EUSUSTEL and in the NEEDS studies).

$$C_{BU} = \frac{A_k}{h_v} - \frac{A_k \cdot P}{h_w} = A_k \cdot \left( \frac{1}{h_F} - \frac{P}{h_W} \right)$$

$C_{BU}$ = Cost Back-Up
$h_v$ = Full loading hours, supply
$h_w$ = Full loading hours of the renewable power station
$P$ = Power credit of the renewable energy plant
$A_k$ = Annuity, incl. the annual fix costs of the Back-Up technology

**Figure 7.** Back-up cost formula used by CASES (2008a).

Even though CASES provide the backup formula, it is still difficult to understand how the backup cost is calculated. No calculation examples are provided and the terms included in the equation are not properly explained. *P* (in the formula) is stated as the capacity factor of the intermittent power plant in the report (CASES, 2008a), but as an unexplained “power credit” in the formula (Figure 7) . It is also unclear what is really meant by the stated annuity ($A_k$) in the formula. This causes confusion and could have been easily avoided by providing a calculation example and a proper explanation of the ingoing parameters.

### 2.10.13 Degradation

Degradation is the loss of energy generation over the lifetime of a given power plant. Two main categories can be distinguished, capacity degradation and heat rate degradation. Capacity degradation happens because of wear and tear of different plant components. It can be partly offset by regular overhauls but the net effect is a loss in peak generating capacity over the expected lifetime. Heat rate degradation is the increase in heat rate due to the aging of power plant equipment. It can be partly offset by regular maintenance but the net effect is an increase in heat rate over the expected lifetime (California Energy Commission, 2010).

None of the reviewed studies except the DECC study on non-renewable technologies (PB, 2011) account for this effect. Capacity degradation is assumed for all gas-fired technologies and for hard coal power plants (simplified to a reduction in the power plants availability).

Degradation mostly seem to be a problem for power plants equipped with gas turbines (California Energy Commission, 2010, Kehlhofer et al., 2009) and for PV panels (Branker et al., 2011). It is unknown to what extent degradation affects the final generation cost result. Most studies do not account for degradation and the impact on the final generation cost in DECC study (PB, 2011)  is unknown. The concept of degradation is not further investigated in this study. Note however that it is a concept not recognized by a majority of the reviewed studies.

# 3 Cost comparison

## 3.1 Investment costs

### 3.1.1 The difference between overnight- and total investment cost

The overnight construction cost is the total cost of building a power plant immediately, i.e. “overnight”. It does not include the interest expenses that occur during the construction period (CASES, 2008a, EUSUSTEL, 2007h).

IEA & NEA (2010) state that the overnight construction cost include pre-construction costs (owner’s costs, e.g. land cost, site works, switchyards, licenses, etc.), construction costs (engineering-procurement-construction cost), and contingencies. The overnight cost constituents do however vary from study to study. For example, not that many studies seem to account for contingencies.

The most common way of accounting for total investment costs is to add the assumed interest expenses during the construction period to the overnight cost. This is however done in some different ways. The construction period, presented in Table 14, and the assumed construction interest rate, presented in Table 15, differ from study to study. Some use the same interest rate during construction (IDC) as for discounting, while other chooses to separate these two. CASES (2008b) use different IDC rates for different power plants. The assumed expense schedule during the construction period also differs from study to study. Both linear and irregular cost outlays are used. All of these parameters have an impact on the investment cost, but choices are generally poorly explained or unjustified.

**Table 14.** Length of construction period in the reviewed studies. The IEA & NEA (2010) figures refer to the median case. The assumed construction period for renewable technologies in the DECC (2011) study is unknown. The nuclear power plants is assumed as FOAK technologies, extending the construction period. EUSUSTEL (2007j) state two different figures for HP, CCGT-C and CCGT-CHP. Which one that has been used is unknown. The construction time for ROR-hydro is stated as 2-5 years and for reservoir hydro as 5-10 years. Elforsk assume longer construction periods for power plants with larger net power output.

| Study | CC | CHP-B | CHP-W | HP | CCGT-C | CCGT-CHP | PV | NP | WP onshore | WP offshore |
|---|---|---|---|---|---|---|---|---|---|---|
| IEA & NEA | 4 | - | - | - | 2 | - | 1 | 7 | 1 | - |
| EUSUSTEL | 4-4.5 | - | - | 2-10 | 2-3 | 1-2 | 1 | 5 | 0.5 | 1 |
| DECC | 3 | - | - | - | 2 | - | - | 6 | - | - |
| Elforsk | 3 | 2-3 | 3 | 2-4 | 3 | 3 | 1 | 6 | 1-2 | 2-3 |

Another topic is if the length, and costs, for the pre-development period should be included in the construction period. The DECC (Mott MacDonald, 2010) studies are the only ones that seem to use such an approach. It is however not known if pre-development costs are accounted for or not.

It is easy to see that differences between the various studies exist. Note that many studies do not state any construction period. This fact is discussed at the end of this section.

**Table 15.** Interest rate during construction [%]. It is assumed that EUSUSTEL use the interest rates presented in this table as nothing else is indicated in the reports.

| Study | CC | CHP-B | CHP-W | HP | CCGT-C | CCGT-CHP | OCGT | PV | NP | WP onshore | WP offshore |
|---|---|---|---|---|---|---|---|---|---|---|---|
| IEA & NEA | 5-10 (same as the discount rate) | | | | | | | | | | |
| CASES | 8.2 | 0 | - | 10-10.8 | 5.4 | 5.4 | 4 | 0 | 10.8 | 0 | 0 |
| EUSUSTEL | 5-10 (same as the discount rate) | | | | | | | | | | |
| Elforsk | 6-10 (same as the discount rate) | | | | | | | | | | |
| EIA | Varies, see appendix C (average after tax WACC = 9.3 %) | | | | | | | | | | |
| SKGS | - | | | | | | | | | | |
| DECC | ? | | | | | | | | | | |
| EWEA | - | | | | | | | | | | |
| VGB | - | | | | | | | | | | |

The assumptions on cost outlay in the reviewed studies are presented in Table 16.

**Table 16.** Allocation of investment cost during the construction period.

| Study | |
|---|---|
| IEA & NEA | linear (country specific where possible) |
| CASES | Unknown |
| EUSUSTEL | Unknown |
| Elforsk | Varies from power plant to power plant |
| SKGS | - |
| DECC | Varies from power plant to power plant |
| VGB | - |
| EIA | Varies from power plant to power plant |

SKGS (PwC, 2010) and VGB (2011) do not mention the IDC topic, hence it is impossible to deduce whether they account for IDC expenses or not. If not, this is rather dubious, especially when considering projects where the construction period can be quite long. There is a significant difference between using overnight- and IDC construction cost. Appendix E presents tables visualising this.

### 3.1.2 Presentation of overnight investment costs

The overnight cost is displayed in box plots showing the minimum value, lower quartile, median, upper quartile and the highest value. The mean value is also included in the diagram. Complete investment cost tables, with IDC costs, can be found in Appendix E.

The overnight investment cost for the power generating technologies is presented in Figure 8. The spread is significantly larger for the renewable technologies compared to the non-renewable alternatives (not including nuclear power). The only renewable technology with an overnight investment cost in the same range as the fossil-fuelled technologies seem to be wind power onshore, although the spread is more pronounced.

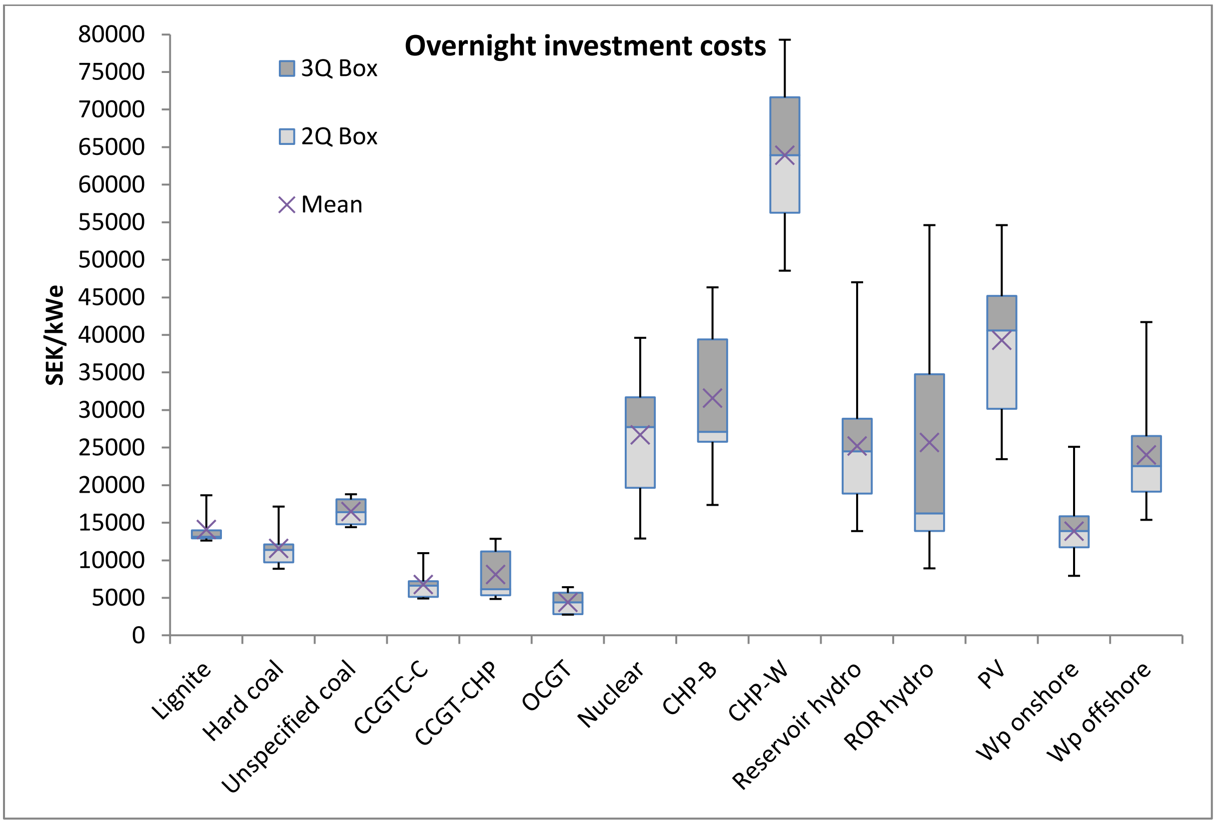


**Figure 8.** Overnight investment cost comparison [SEK/kW$_e$].

The total spread and the mean value is very sensitive to extreme values. The interquartile range (the distance between the upper and lower quartile, i.e. where 50% of the reported cost figures can be located) is less affected by extreme values and might therefore be a better measure of the spread in the result. As Figure 8 shows, the spread is still significant for many of the power generating technologies even if we apply this measure.

One explanation to the CHP-B-, PV- and hydropower spread is economies of scale. The overnight investment cost (per kW$_e$) is smaller for larger plants (Appendix E). The investment cost for hydropower plants also seem to be very site specific (IEA, 2010a). This is a probable explanation to the significant spread in the hydropower investment cost figures. A similar observation can be made for PV, where the type of application (e.g. rooftop- or open-air installations) seem to be a major cost factor (IEA, 2010b). Observe that the overnight cost figures for CHP-W are based on only two data points and that the data in general is limited.

It is not possible to deduce where the costs differ. The reason is the already mentioned problem of reporting costs without specifying the different cost components in a numerical way. This is from now on referred to as the *component issue*.

### 3.1.3 General comments on the investment cost figures

The numbers of data points used when calculating the different statistical measures are limited. This is especially true for some power generating technologies such as CHP-B, CHP-W and OCGT. It is therefore possible that the different measures could vary substantially by including more data points. The presented spread will however not be smaller than what is indicated in this study. The spread is therefore very useful in showing the risk of using a cost figure from a certain study in an uncritical way.

Appendix E shows that the reported overnight cost figures vary significantly with the station size, even within the same study. This clearly indicates that economies of scale is an important factor when it comes to overnight investment costs. Another point worth mentioning is the differences in investment cost between different countries. It is very difficult to figure out how different country specific parameters such as wages, taxes, customs, shipping and price on raw materials affect the investment cost and the total electricity generation cost due to the component issue. Indicators do however suggest that this impact might be significant. This is further discussed in chapter 7.

Ekholm's (2012) opinion is that at least material, fuel and labour costs should differ between different countries. Parameter cost components that have been estimated for a similar economy should therefore always be used. Henryson (2012) state that international studies can be used on a comprehensive level. Precise assessments must however be based on national assumptions.

Time seems to be another important factor when it comes to power plant investment costs. As Figure 9 shows, capital costs have risen considerably for some Swedish power generating technologies during the last decade. Figure 9 also shows a trend in increasing capital costs at an international level.

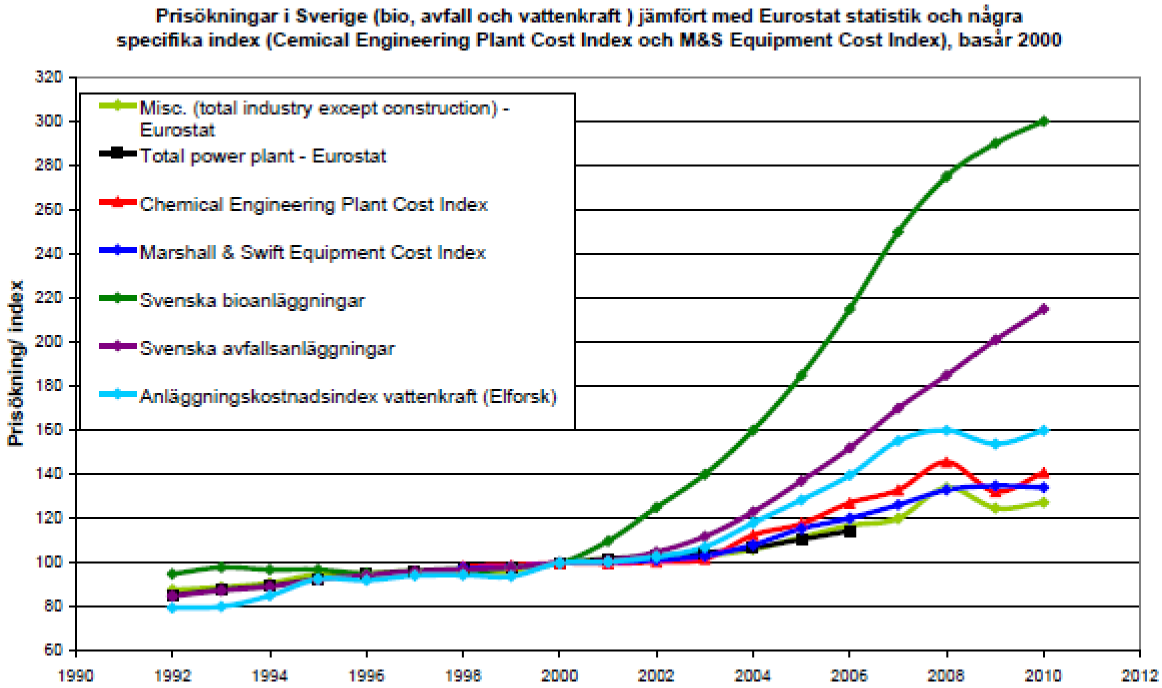


**Figure 9.** International capital cost indexes and Swedish price increases (Elforsk, 2011b). Svenska bioanläggningar = Swedish biomass power plants, Svenska avfallsanläggningar = Swedish waste power plants, Anläggningskostnadsindex vattenkraft = cost index for hydropower plants. The price increases for biomass and waste power plants can be explained by a significant steal price increase and a large increase in demand.

Another example of power plant capital cost increases during the last decade is provided in Figure 10. It shows the EPCCI index, an index that tracks, and forecasts, the cost of building European coal-, gas-, wind- and nuclear power plants (indexed to year 2000). The cost increases can be partly explained by rising prices on steel, copper and oil, something that drive up equipment- and material costs (IHS, 2011).

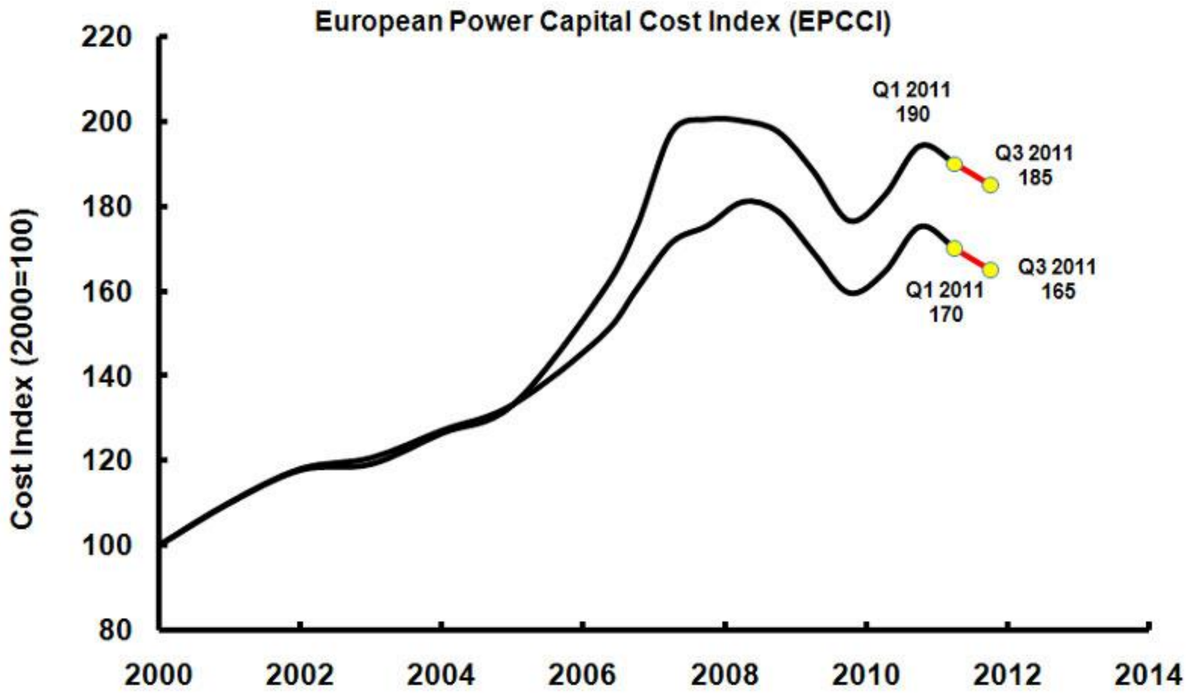


**Figure 10.** EPCCI index (IHS, 2012). The lower curve excludes nuclear power plants.

Figure 9 and Figure 10 shows that capital costs can change rapidly with time. This is something that needs consideration when dealing with electricity generation cost assessments.

Another indicator on that time is a crucial factor is that the NEEDS results were updated shortly after the project was finished due to some outdated cost figures (Hirschberg, 2012). Henryson (2012) state that cost assessments have to be updated regularly and that the frequency depends on technology development. Ekholm's (2012) opinion is that it is difficult to estimate for how many years assessments might be relevant. If a change in trend occurs (such as technological breakthroughs, jump in certain prices, and policy changes), this might make old analyses obsolete.

## 3.2 O&M cost figures

O&M costs are often stated as either being fixed or variable. Fixed O&M costs often include costs of labour, insurances, surveillance, spare parts, etc. Variable O&M costs include the costs for maintenance, contracted personnel, materials, disposal of waste, and more. Table 17 shows that studies tend to display O&M costs in different ways. This is an issue as it becomes more difficult to compare studies with each other.

**Table 17.** O&M cost base. For all power generating technologies, except nuclear power, wind power, PV and hydropower, Elforsk (2011b) presents O&M costs as a cost per MWh of fuel spent.

| Study | Cost/kW | Cost/MWhe | Cost/MWhf | Annual % of investment |
|---|---|---|---|---|
| IEA & NEA | | x | | |
| CASES | x | x | | |
| EUSUSTEL | x | x | | |
| Elforsk | x | x* | x | |
| NEEDS | | | | |
| SKGS | | x | | |
| DECC | x | x | | |
| EWEA | | x | | |
| IEA, RM | | | | X |
| EIA | x | x | | |
| VGB | | | | X |

After some investigation it became evident that all of the reviewed studies seem to assume constant O&M costs throughout the power plants lifetime (meaning that these costs already are levelised). Most of the studies also present their O&M costs in such a way that it is possible to recalculate- or directly present them by using a common base.

The assumed O&M costs for non-renewable power plants are shown in Figure 11. The cost figures have all been recalculated to a cost per MWh of electricity produced. Most of the reported values are below 100 SEK/MWh$_e$, indicating that O&M costs are not a major cost driver for non-renewable technologies. It is still interesting to notice the spread in the presented figures, especially for CCGT power plants. There is a significant difference between using an O&M cost figure of some 10 SEK/MWh$_e$ compared to 200 SEK/MWh$_e$.

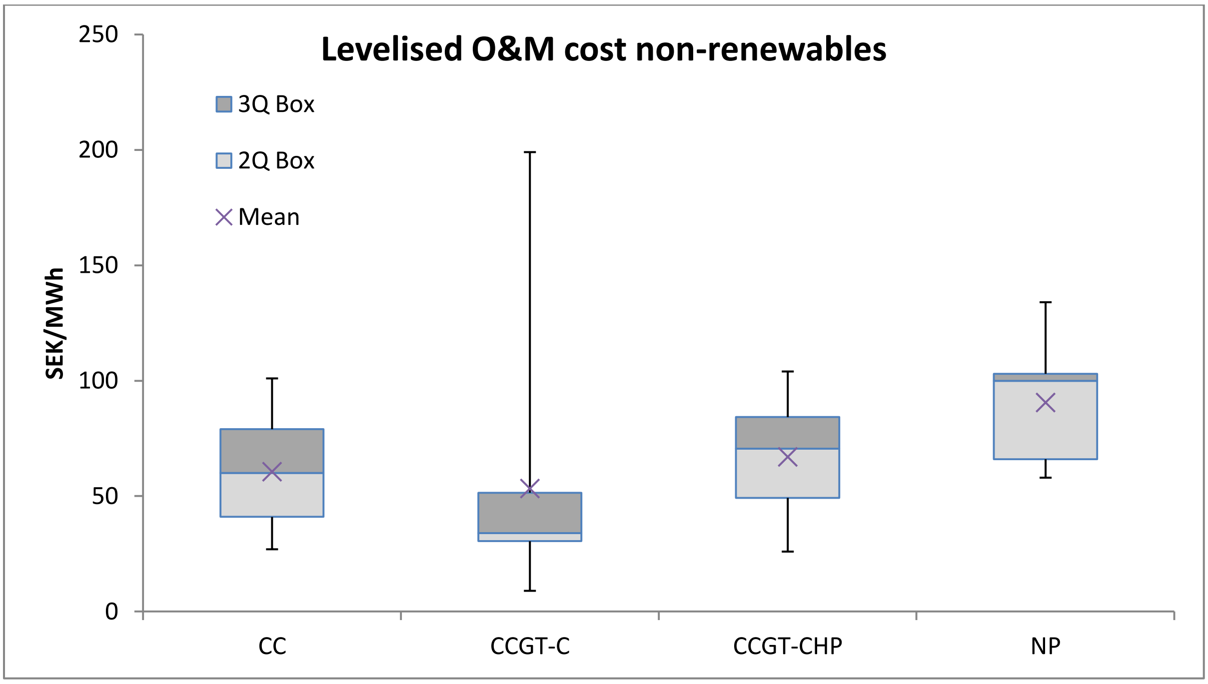


**Figure 11.** Levelised O&M cost non-renewable power generating technologies.

Figure 12 shows the levelised O&M costs for renewable technologies. They are in most cases higher than the reported figures for non-renewables. Hydropower and wind power onshore are approximately within the same range as the non-renewable alternatives. The spread is in most cases significant with some really high reported values for firstly PV, but also for wind power offshore and CHP-W.

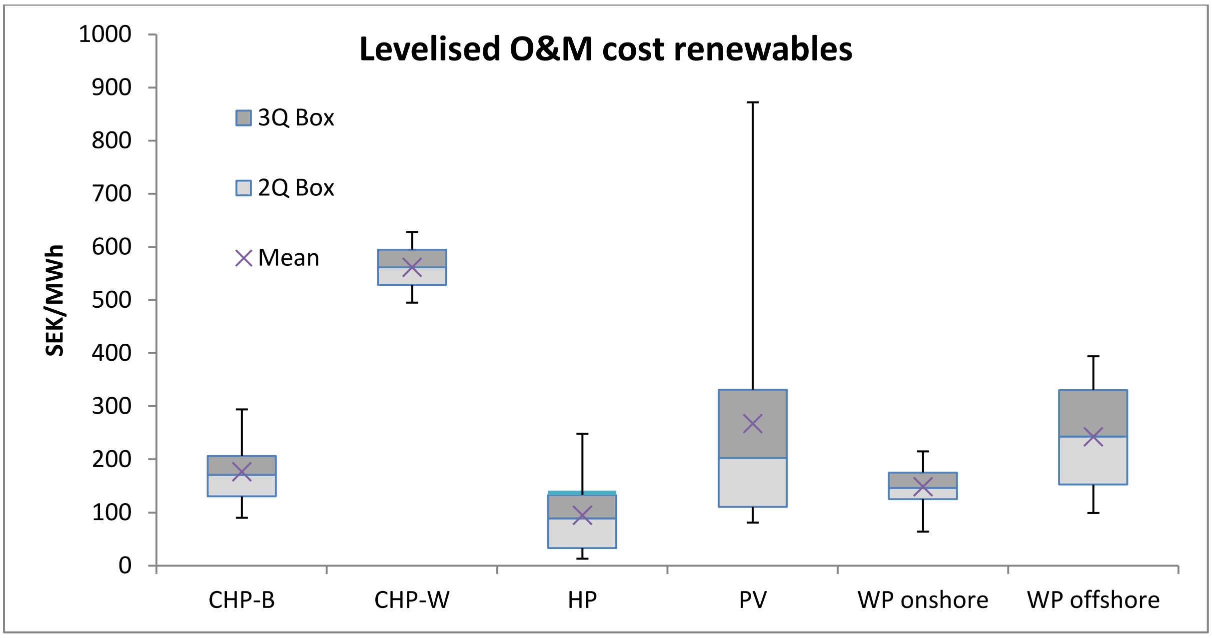


**Figure 12.** Levelised O&M cost renewables.

Figure 12 does not include the hydropower figures presented in the EUSUSTEL study. These are extreme values and they seem to be too high to properly reflect O&M costs for hydropower plants, a technology mostly associated with low marginal costs. The impact of including the EUSUSTEL O&M cost is visualised in Figure 13.

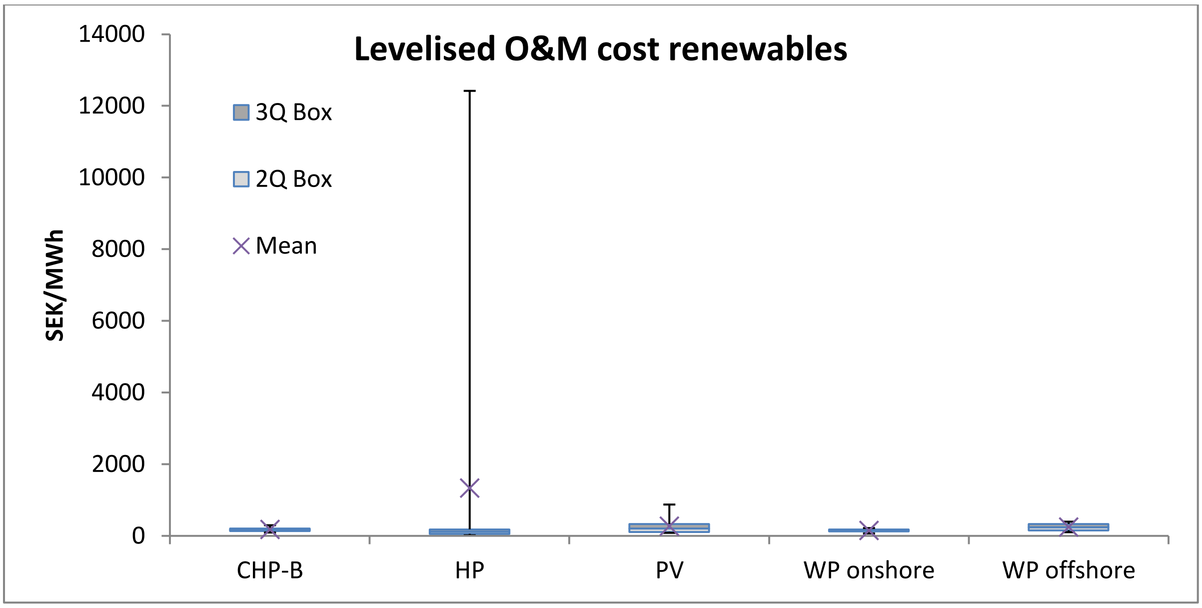


**Figure 13.** Levelised O&M cost renewables (including the EUSUSTEL figures).

EUSUSTEL presents O&M cost figures in the range of 163-8125 SEK/MWh$_e$ for ROR-hydro and 1690-3315 SEK/MWh$_e$ for reservoir hydro (EUSUSTEL, 2007h). These are extreme values and leads to very high generation cost figures. It is dubious that EUSUSTEL use these figures without any discussion of their plausibility.

There is a large spread in the reported figures, but it is very difficult to assess why the reviewed studies arrive at such different estimates. Appendix F presents the reported O&M cost figures in table format. The reasons for the discrepancies between different studies are impossible to know because of the component issue.

## 3.3 Fuel cost

Fuel costs are heavily affected by assumptions on fuel price and plant efficiency. These factors are important to keep in mind when looking at the presented fuel cost figures in Figure 14. If we look at the middle 50% of the reported values these fall within a pretty narrow range. The total spread is however significant. The spread for lignite coal is due to only one extreme value while the reported fuel cost figures for CHP-B and CHP-CCGT are more diverse. The fuel costs are present in table format in Appendix G.

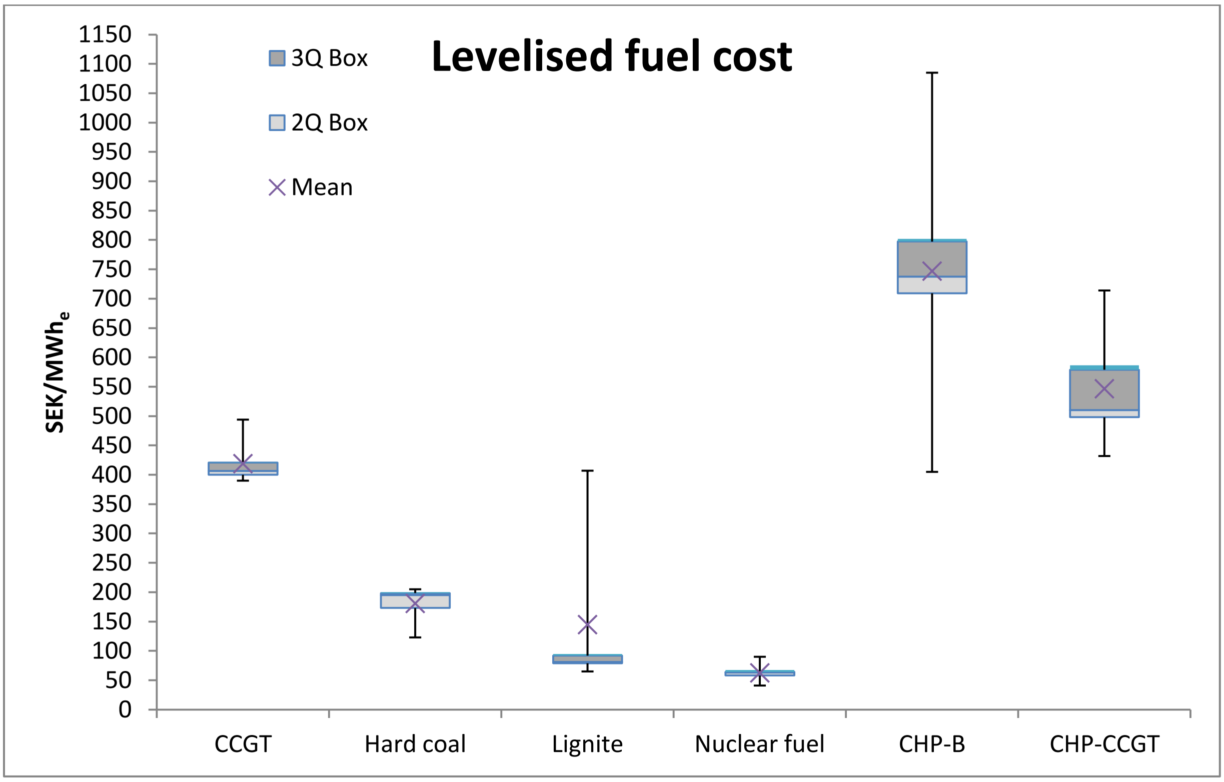


**Figure 14.** Levelised fuel cost in the reviewed studies [SEK/MWh$_e$].

Note that CHP-W fuel costs are omitted from Figure 14 as these costs are negative. The reported fuel cost figures for CHP-W is -639 SEK/MWh$_f$, respectively -1599 SEK/MWh$_f$.

## 3.4 Carbon dioxide emission costs

The discrepancies in the levelised carbon dioxide emission costs presented in Table 18 are due to different assumptions on carbon dioxide emission fees, but also on the assumed efficiencies and on the assumed carbon content of the fuel. None of the reviewed studies provide any information on the assumed carbon content of the fuels. Neither does any study provide an example of how they calculate the carbon dioxide emissions. It is therefore difficult to completely understand why the studies arrive at such different results.

It is important to make sure that the reader is aware that carbon costs are included in the reported generation costs. Carbon emission costs have a large impact on the reported generation cost figures, especially for hard coal power plants. For example, the DECC (PB, 2011) figure on hard coal is certainly high enough to change the opinion of how the generation cost for coal power fares in comparison to other power generating technologies.

**Table 18.** Levelised carbon dioxide emission cost [SEK/MWh$_e$]. The IEA & NEA median case is a mix of lignite and hard coal power plants.

| Study | CC hard coal | CC lignite | CCGT-C | CCGT-CHP | OCGT |
|---|---|---|---|---|---|
| VGB | 244 | 253 | 126 | | 144 |
| DECC | 507 | | 192 | | |
| IEA & NEA, median case | 162 | * | 71 | | |
| IEA & NEA, min | 149 | 170 | 69 | 61 | |
| IEA & NEA, max | 159 | 184 | 76 | 101 | |
| EUSUSTEL | 69 | 88 | 33-36 | - | |

## 3.5 Backup power costs

Table 19 presents the assumption on backup costs for wind power in the relevant studies. The generation cost increases by some 15-50% depending on study and assumption on backup power plant.

**Table 19.** Levelised backup cost for wind power [SEK/MWh$_e$]. For minimum backup cost a hard coal condensing power plant is used. Maximum backup cost is provided by a CCGT power plant (CASES, 2008a, EUSUSTEL, 2007d).

| Study | DR [%] | Generation cost | With min backup cost | With max backup cost | Difference min (%) | Difference max (%) |
|---|---|---|---|---|---|---|
| **Wind power onshore** | | | | | | |
| CASES, 2 MW | 5 | 454 | 542 | 607 | 119 | 134 |
| | 10 | 595 | 713 | 809 | 120 | 136 |
| EUSUSTEL, 0,75 MW | 5 | 351 | 442 | 510 | 126 | 145 |
| | 10 | 482 | 612 | 724 | 127 | 150 |
| EUSUSTEL, 2 MW | 5 | 457 | 546 | 612 | 119 | 134 |
| | 10 | 640 | 767 | 875 | 120 | 137 |
| NEEDS | 5 | 681 | 791 | - | 116 | - |
| **Wind power offshore** | | | | | | |
| CASES, 2 MW | 5 | 473 | 564 | 631 | 119 | 133 |
| | 10 | 624 | 747 | 857 | 120 | 137 |
| EUSUSTEL, 2 MW min | 5 | 396 | 492 | 565 | 124 | 143 |
| | 10 | 553 | 692 | 810 | 125 | 146 |
| EUSUSTEL, 2 MW max | 5 | 725 | 817 | 886 | 113 | 122 |
| | 10 | 1033 | 1164 | 1276 | 113 | 124 |

Accounting for backup power costs is clearly not an evident or an easy task. Most studies do not account for backup costs and the methodology used in CASES (2008a), NEEDS (2009b) and EUSUSTEL (2007h) is poorly motivated and not thoroughly explained. From a Nordic point of view, it can be argued that hydropower should be used as backup power provider. It is confusing that EUSUSTEL assumes backup costs for reservoir hydropower without any explanation of this matter.

## 3.6 Generation costs

The generation cost is presented by using either a 5%- or a 10% discount rate (DR). This means that studies using other discount rates fall outside of this comparison. A complete list of all generation cost figures can be found in table format in Appendix H.

### 3.6.1 Generation cost for non-renewable technologies

The electricity generation costs for non-renewable power generating technologies are presented in Figure 15. Note that the presented generation cost figures does not include the assumptions on carbon dioxide emission costs.

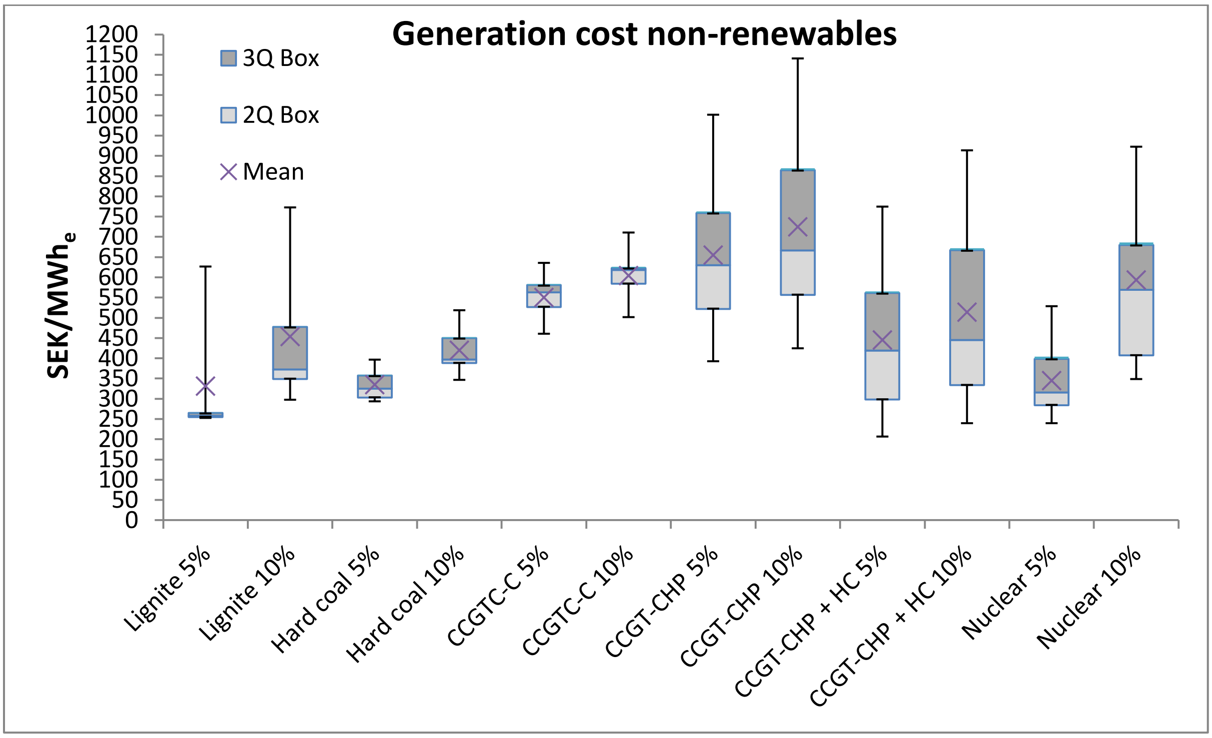


**Figure 15.** Generation cost non-renewables.

The most important thing that Figure 15 visualises is the large spread in the reported results and the impact of discount rates and heat credits. The spread is striking for CCGT-CHP, nuclear power and lignite coal, while the other fossil-fuelled technologies display more lumped figures. The large spread for lignite coal in the 5% DR case is due to a few extreme values, something that is visualised by the small IQR.

The impact of including carbon dioxide emission costs is visualised in Figure 16. It shows the generation cost for hard coal and CCGT-C (at 10% DR), with and without carbon cost. The carbon emission costs effectively raise the mean generation cost for hard coal power plants with some 42% and for CCGT-C by approximately 16%.

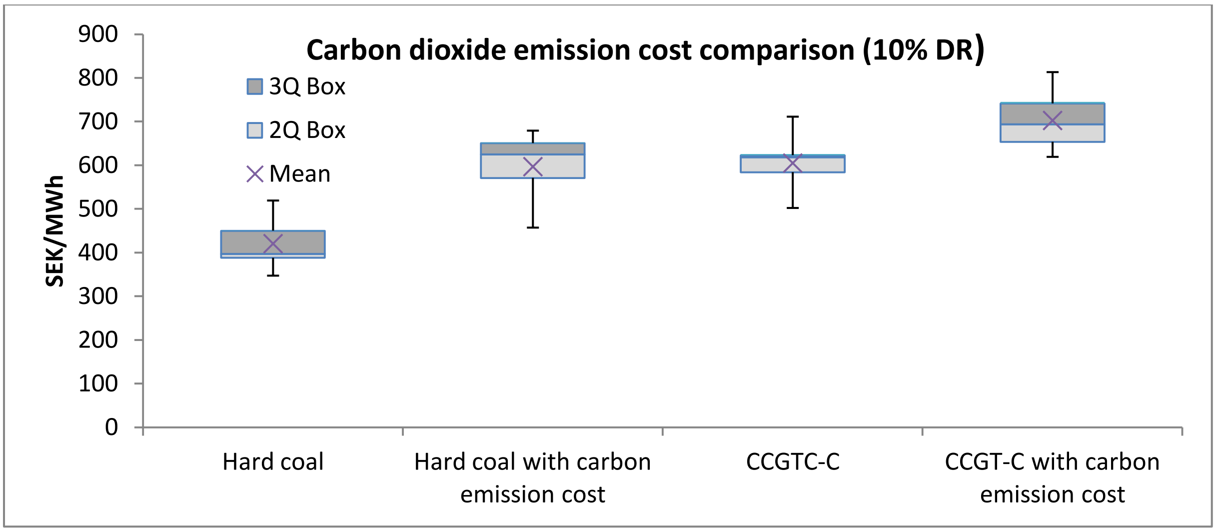


**Figure 16.** Generation cost (with and without carbon dioxide emission cost) for hard coal- and CCGT-C power plants (10% DR).

### 3.6.2 Generation cost renewable technologies

The generation cost for wind power and CHP-B power plants is presented in Figure 17. There is a significant spread, and a large IQR, in all cases. The discount rate is a major cost driver for all technologies and the impact of heat credits on CHP-B generation costs is significant.

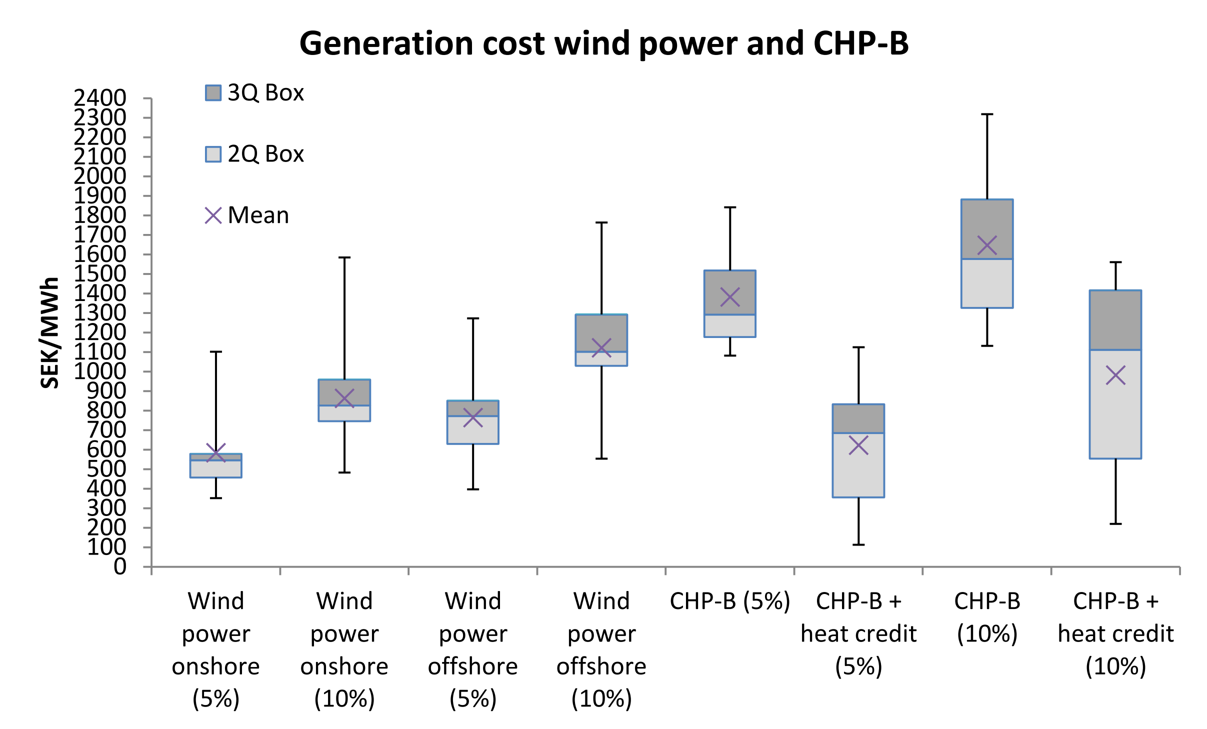


**Figure 17.** Wind power and CHP-B generation cost (5% and 10% discount rate). The generation cost for CHP-B at 5% DR has been excluded due to few data points.

The electricity generation cost for hydropower and PV is presented in Figure 18. It is impossible not to notice the significant spread. The spread for ROR-hydro is due to an extreme O&M cost figure in the EUSUSTEL (2007h) study. Note also that the generation cost for reservoir hydro is about the same in both the 5%- and in the 10% DR case. This is due to the inclusion of the significantly smaller Elforsk (2011b) figures in the 10% DR case (Elforsk figures are not present in the 5% discount rate case as Elforsk do not use this assumption on DR). This once again indicates that hydropower generation costs are highly variable and site-specific.

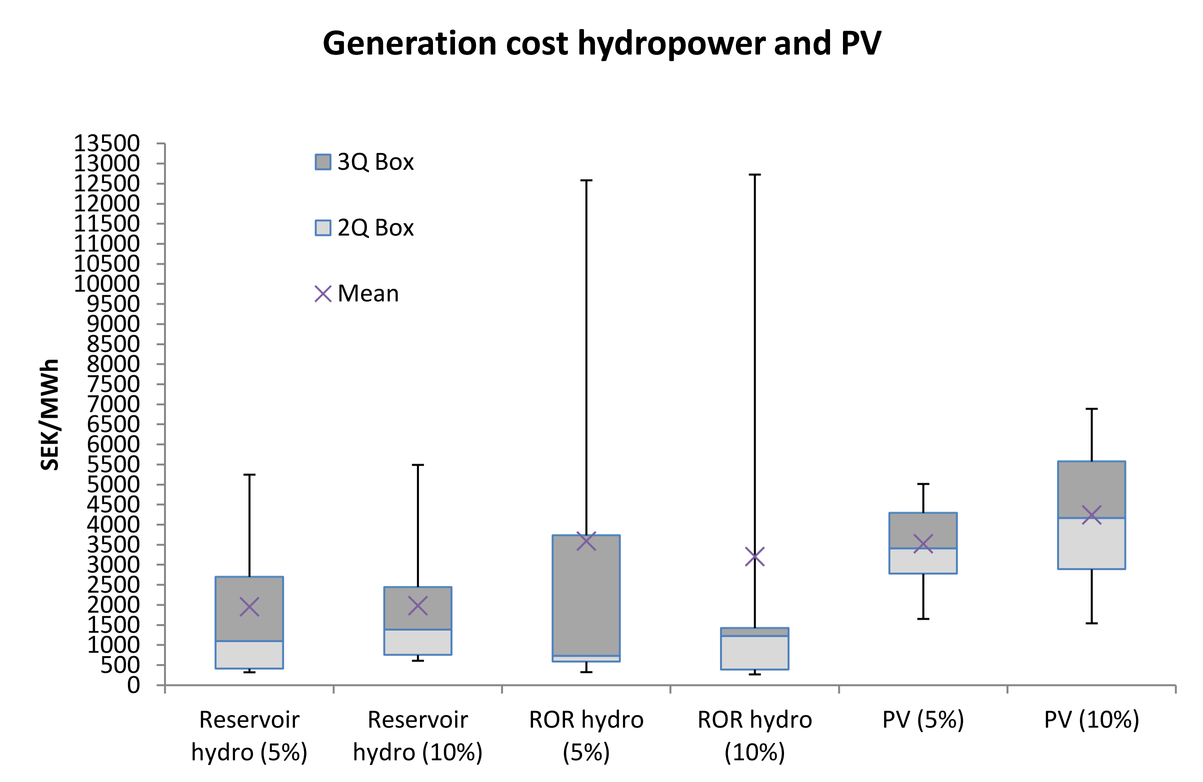


**Figure 18.** Hydropower and PV generation cost (5% and 10% discount rate).

### 3.6.3 Generation cost comparison

This section presents the generation cost figures by using the same scale, thereby facilitating a comparison of the quantity of data. The generation cost at 5% DR is presented in Figure 19, while Figure 20 shows the generation cost at 10% DR. Observe that the generation cost scale is truncated at 2000 SEK/MWh$_e$.

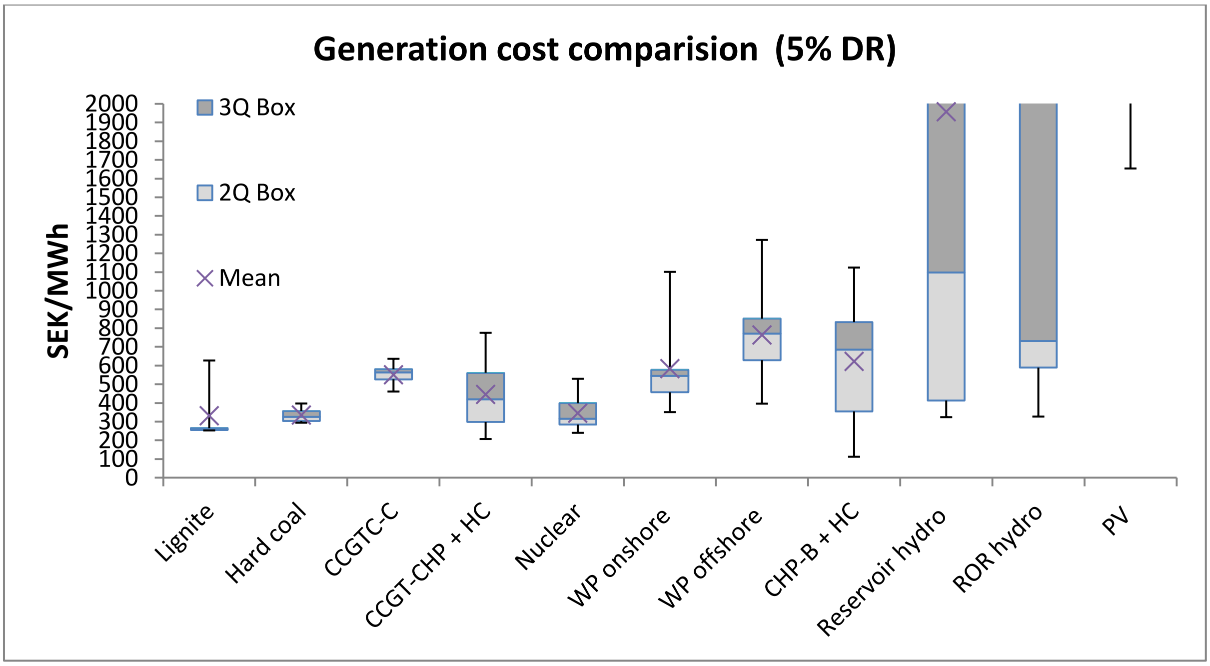


**Figure 19.** Generation cost comparison at 5% DR. Observe that the scale is truncated at 2000 SEK/MWhe.

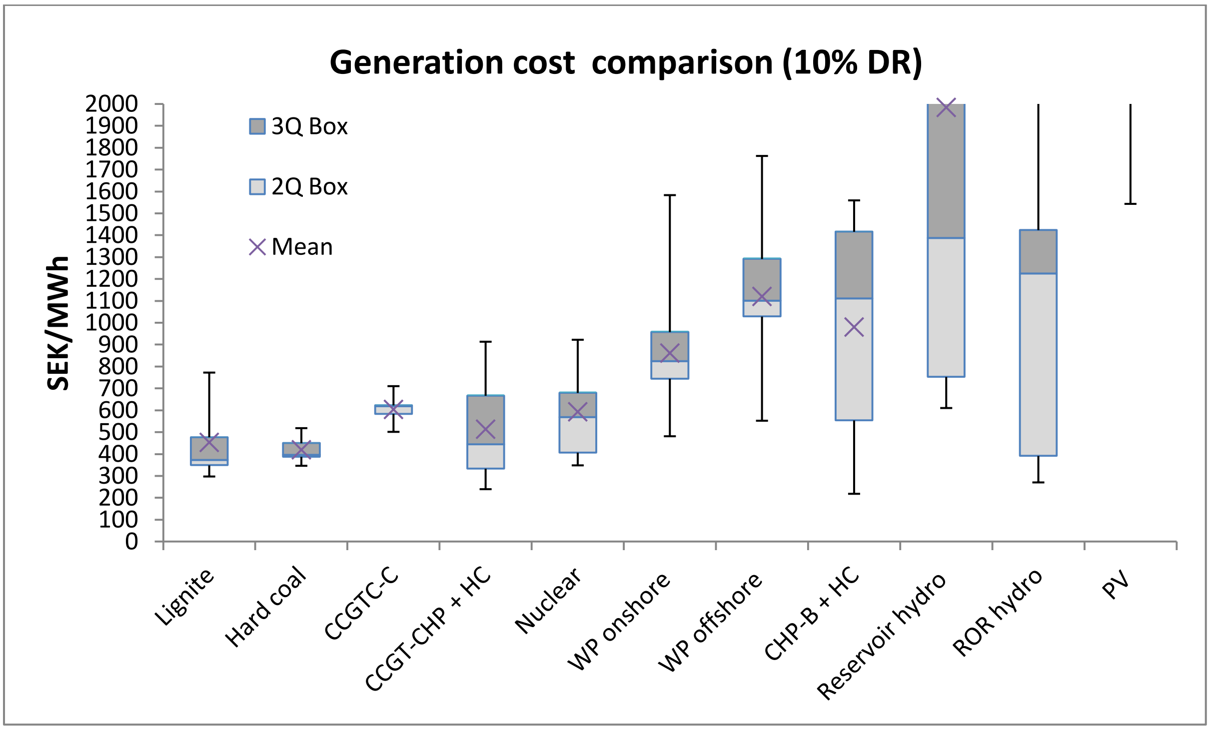


**Figure 20.** Generation cost comparison at 10% DR. Observe that the scale is truncated at 2000 SEK/MWhe.

The significant spread in the reported electricity generation cost figures is important to notice as most of the reviewed studies generalise their reported electricity generation cost results. The figures presented in this section do, however, indicate that it is difficult to generalise electricity generation costs. One should therefore be careful when looking at generalised electricity generation cost results.

Hirschberg (2012) agrees that caution when looking at electricity generation costs is recommended. The reason is not just about costs but also on independent evaluations. There is a shortage of independent, publicly available studies that benefit from inputs of those involved (such as industries and regulators), even if the results are not favourable to the participants providing the necessary input. In addition to this, no one knows the real costs of a power generating technology. The only people with insights in such costs are vendors, and they are subject to conditions on the market. Ekholm (2012) state that people in general might not be aware of the limits in the calculations, but the real problem is when unaware persons have decision power. Ekholm (2012) hopes that all decision makers are well-informed, but it is not something that is necessarily the case in reality.

# 4 Sensitivity analysis

The methodological differences and the presented cost figures indicate that some parameters have a major impact on the electricity generation cost. It is therefore essential to perform a sensitivity analysis in order to be able to understand the uncertainties in the assessments, the impact of specific parameters, and also to get a better understanding of the impact of certain assumptions. However, most of the reviewed studies do not include a detailed sensitivity analysis in their reports.

## 4.1 Sensitivity analysis in the reviewed studies

Elforsk (2011) finds it unnecessary to include a detailed sensitivity analysis in their report as they provide the model to the readers, thereby making it possible to perform own sensitivity analyses. It is however questionable if the average reader would take the time to do so.

SKGS (PwC, 2010) and VGB (2011) perform a kind of sensitivity analysis on the investment cost but not on any other parameters. The results are presented as different cases where the only varied parameter is the investment cost.

CASES (2008b) state that detailed sensitivity analyses have been performed for all power generating technologies. The only one presented is however the impact of changes in the capacity factor on the final generation cost. EUSUSTEL (2007d) also choose to perform a sensitivity analysis on the capacity factor while ignoring the other parameters.

The DECC studies (Arup, 2011, PB, 2011) present three different cases (for each technology) where parameters such as the operating period, plant efficiency, availability, capital costs and O&M costs are varied. The generation cost is presented by using assumptions on a low, a medium and a high figure for all varied parameters. The parameters are thereby not varied individually but instead as a whole. This is a good example of how costs might change if multiple parameters are varied at the same time. The impacts of changes in individual parameters do however fail to show.

IEA & NEA (2010) is the only study that performs detailed sensitivity analyses. Tested parameters are the capacity factor, discount rate, construction cost, lifetime, fuel cost, lead time and carbon cost. Sensitivity analyses are however not performed for all included power generating technologies.

There are indicators on that detailed sensitivity analyses were performed in the NEEDS study. There is a report describing how the analyses were made and which parameters that were tested (NEEDS, 2008a). The findings can however not be located in any of the different NEEDS reports (NEEDS, 2009a).

EWEA (2009) tests the impact of the capacity factor, and to a lesser extent also the impact of the discount rate and the investment cost on the final generation cost. IEA (2010b) presents the PV generation cost by assuming different applications (e.g. rooftop- vs. large scale installations), and by using three different assumptions on the capacity factor. No sensitivity analysis is included in the WEO2009 (IEA, 2009) study.

## 4.2 Sensitivity analysis using a LCOE model

As detailed sensitivity analyses seem rather rare, a levelised electricity cost (LCOE) model has been implemented in order to provide some explanations to why there is such a large spread in the reported electricity generation cost figures. The sensitivity analyses were performed with a spreadsheet model based on the LCOE formula suggested by IEA & NEA (Figure 2).

The median values from the total data compilation were used as input parameters. They were chosen due to the wide dispersion of the data. The fuel prices have been collected from Elforsk (2011b), as it is the only one of the reviewed studies that provide data on (almost) all fuels needed. The missing price on lignite coal is taken from the other relevant studies (using the median value).

All assumptions on input parameters are summarised in Appendix I. These were used to set up the base case presented in Figure 21 and in Table 20.

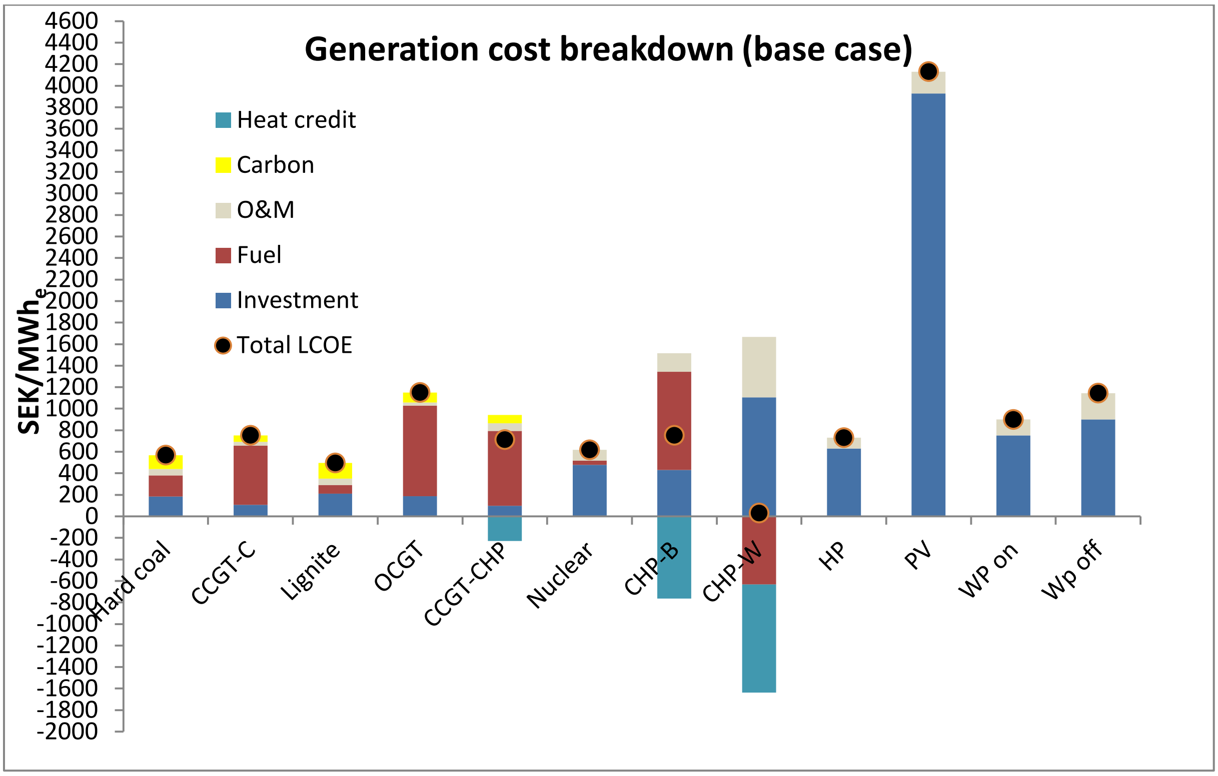


**Figure 21.** Generation cost breakdown (base case).

**Table 20.** Generation cost breakdown (base case) [SEK/MWh$_e$].

| [SEK/MWh$_e$] | Hard coal | CCGT-C | Lignite | OCGT | CCGT-CHP | Nuclear | CHP-B | CHP-W | HP | PV | WP on | Wp off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total LCOE | 568 | 752 | 495 | 1150 | 712 | 617 | 752 | 30 | 730 | 4131 | 899 | 1144 |
| Investment | 184 | 106 | 212 | 187 | 98 | 478 | 431 | 1104 | 629 | 3928 | 753 | 901 |
| Fuel | 196 | 552 | 80 | 842 | 696 | 39 | 913 | -632 | 0 | 0 | 0 | 0 |
| O&M | 60 | 34 | 60 | 29 | 71 | 100 | 171 | 562 | 101 | 203 | 146 | 243 |
| Carbon | 128 | 60 | 143 | 92 | 76 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Heat credit | 0 | 0 | 0 | 0 | -229 | 0 | -763 | -1004 | 0 | 0 | 0 | 0 |

The sensitivity analyses are conducted by using the base case as initial position. Note that fuel prices, carbon emission costs and O&M costs are assumed as being constant in time in the base case. Appendix J provides a visualisation of the model. It shows the setup of the hard coal power plant base case.

### 4.2.1 Impact of changing major cost parameters

This section presents the impact on the LCOE by changing the major cost parameters by either +25% or by -25%. These values fall well within the total spread presented in chapter 3. The tested parameters are presented in Table 21. The impact of changes in the capacity factor for the baseload technologies is tested later on. Note that the capacity factor and the heat credits have a reverse impact on the generation cost.

**Table 21.** Tested parameters in the sensitivity analysis. The tested parameters are indicated by the “x” symbol.

| Parameter | Hard coal | Lignite | CCGT-C | CCGT-CHP | OCGT | Nuclear | CHP-B | CHP-W | Hydro | PV | Wp on | WP off |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity factor | - | - | - | - | x | - | - | - | x | x | x | X |
| Fuel price | x | x | x | x | x | x | x | x | - | - | - | - |
| Constructon cost | x | x | x | x | x | x | x | x | x | x | x | X |
| Discount rate | x | x | x | x | x | x | x | x | x | x | x | X |
| Carbon price | x | x | x | x | x | - | - | - | - | - | - | - |
| Lifetime | x | x | x | x | x | x | x | x | x | x | x | X |
| O&M cost | x | x | x | x | x | x | x | x | x | x | x | X |
| Lead time | x | x | x | x | x | x | x | x | x | x | x | X |
| Heat credit | - | - | - | x | - | - | x | x | - | - | - | - |

Figure 22 shows the result from the hard coal sensitivity analysis. The sensitivity is visualised in a tornado graph showing the relative impact from each tested parameter. The parameter with the biggest impact on the LCOE result is presented at the top of the graph. Note that each parameter is tested individually. A change in multiple parameters at the same time might therefore have a significantly larger impact on the generation cost result. The sensitivity to changes in multiple parameters will also be visualised in this chapter.

The hard coal power plant is fairly sensitive to changes in fuel price, discount rate, construction cost and carbon price. The impact is however not that significant given the relative large change in the input parameters.

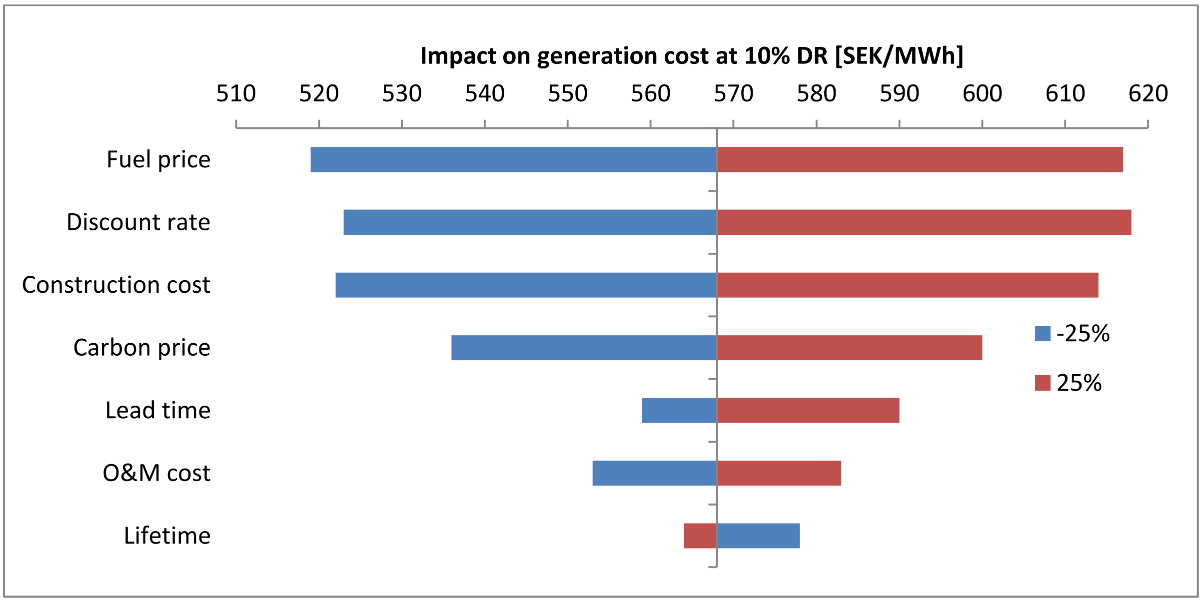


**Figure 22.** Hard coal LCOE sensitivity analysis result.

The result from the sensitivity analysis on lignite coal is presented in Figure 23. Note that the impact of fuel prices is much less than for the hard coal power plant. The price on lignite coal tend to be very country-specific and it is not traded on an international market (IEA and NEA, 2010). Using lignite fuel prices on a general basis should be done with caution.

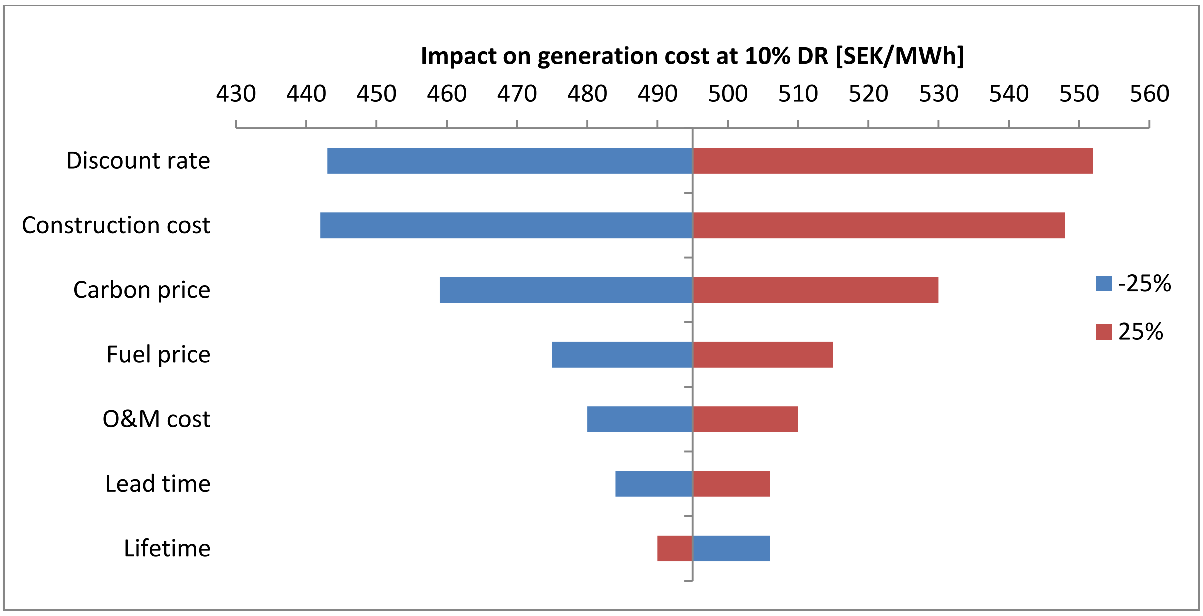


**Figure 23.** Lignite coal LCOE sensitivity analysis result.

The low impact of changes in fuel price renders the lignite power plant to be most sensitive to changes in construction cost and discount rate, even though the power plant is using a fossil-fuel to produce the electricity. This picture is completely reversed if we look at Figure 24,

Figure 25 and Figure 26, showing the sensitivity analysis result for CCGT-C, CCGT-CHP and OCGT power plants. These technologies are all using natural gas to produce electricity, something that makes them very vulnerable to changes in fuel price, given the higher price on natural gas compared to coal.

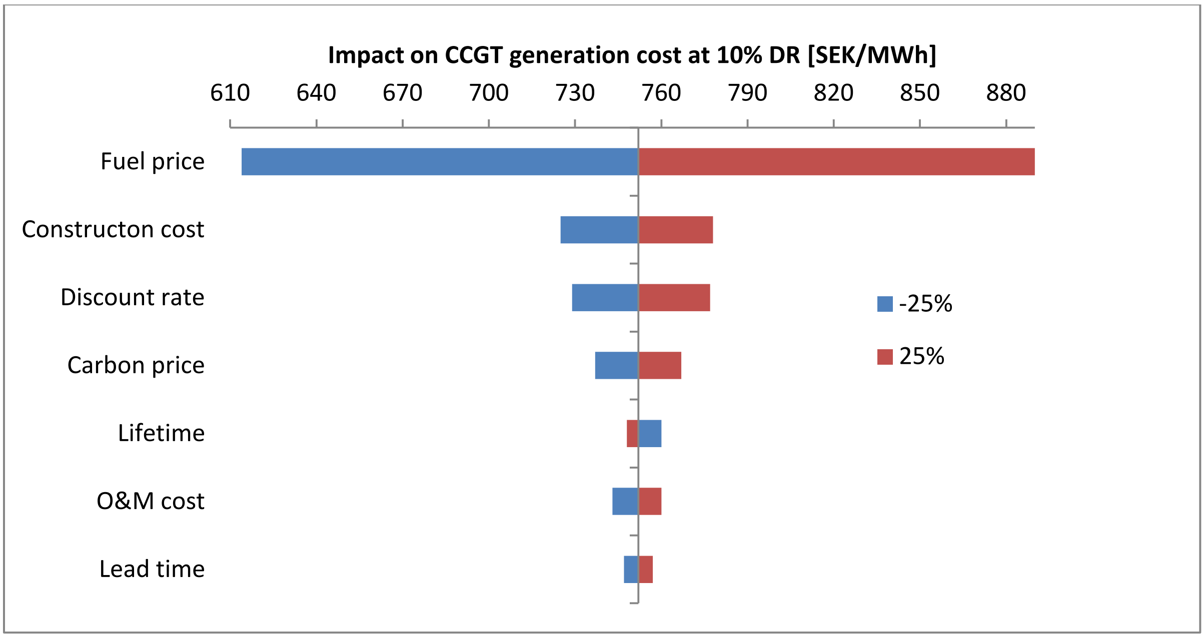


**Figure 24.** CCGT-C LCOE sensitivity analysis result.

Figure 24 shows that CCGT-C plants seem to be very resistant to changes in all input parameters except the fuel price. This effect is however significant, making CCGT power plants very sensitive to any changes in the fuel price assumption.

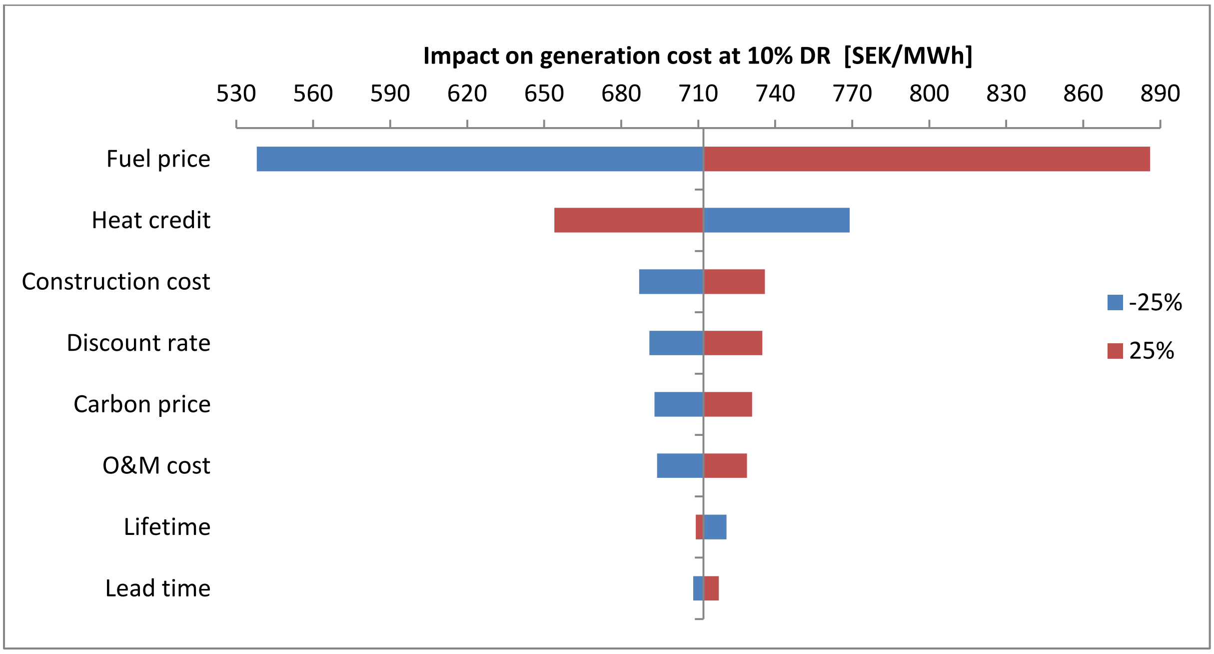


**Figure 25.** CCGT-CHP LCOE sensitivity analysis result.

Figure 25 shows that the sensitivity for CCGT-CHP is very similar to the impact on CCGT-C. The fuel price has a significant impact on the LCOE while changes in the other parameters only contributes to small changes in the generation cost.

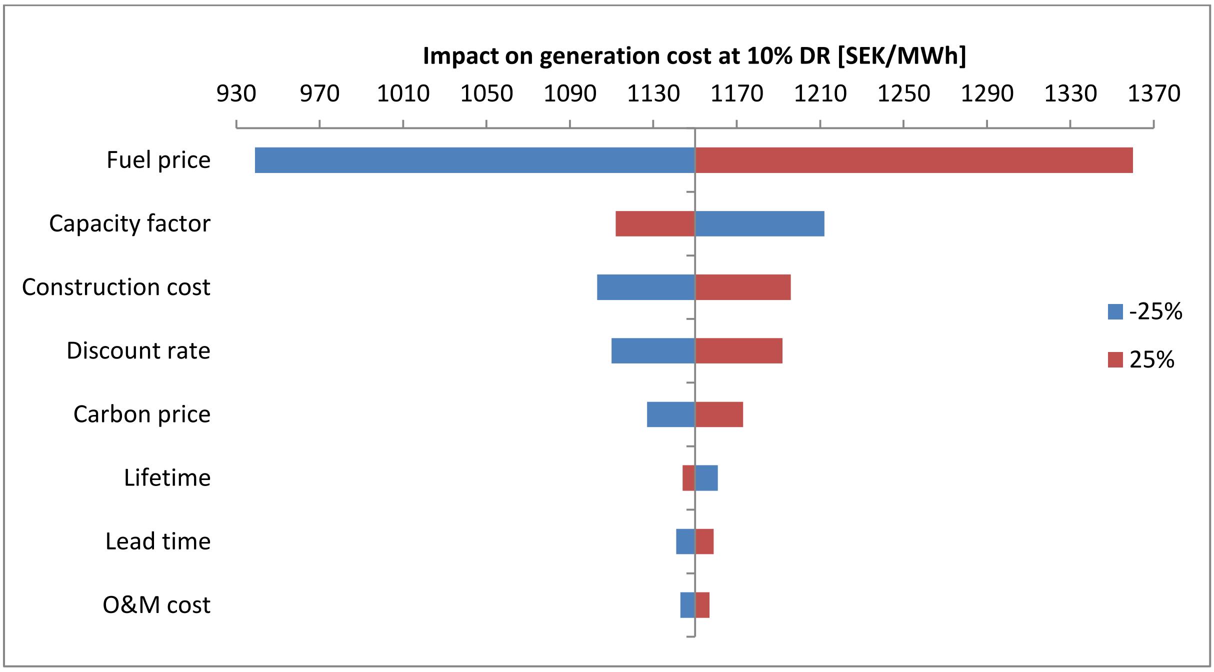


**Figure 26.** OCGT LCOE sensitivity analysis result.

Figure 26 shows the sensitivity for OCGT. It is very similar to the results for CCGT-C and CCGT-CHP power plants. Observe that the capacity factor is not the major cost driver even though it is assumed to be quite low in the base case compared to the baseload technologies.

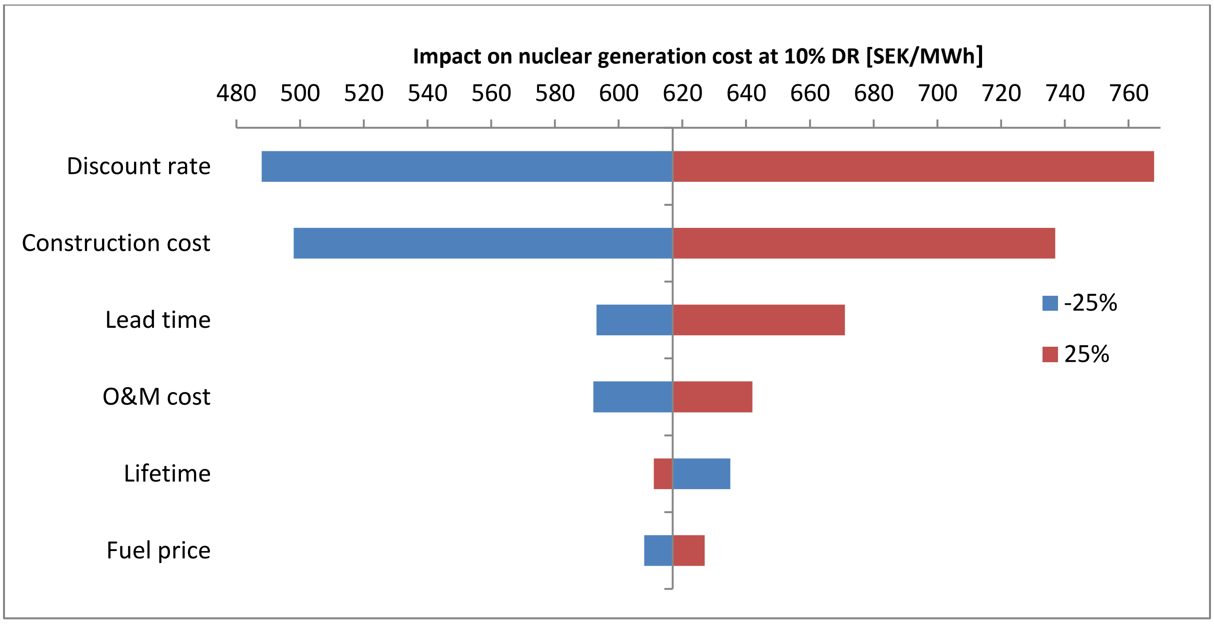


**Figure 27.** Nuclear LCOE sensitivity analysis result.

Figure 27 shows that the LCOE for nuclear power is heavily affected by changes in the discount rate and by changes in the investment cost. Note the insensitivity to changes in fuel price.

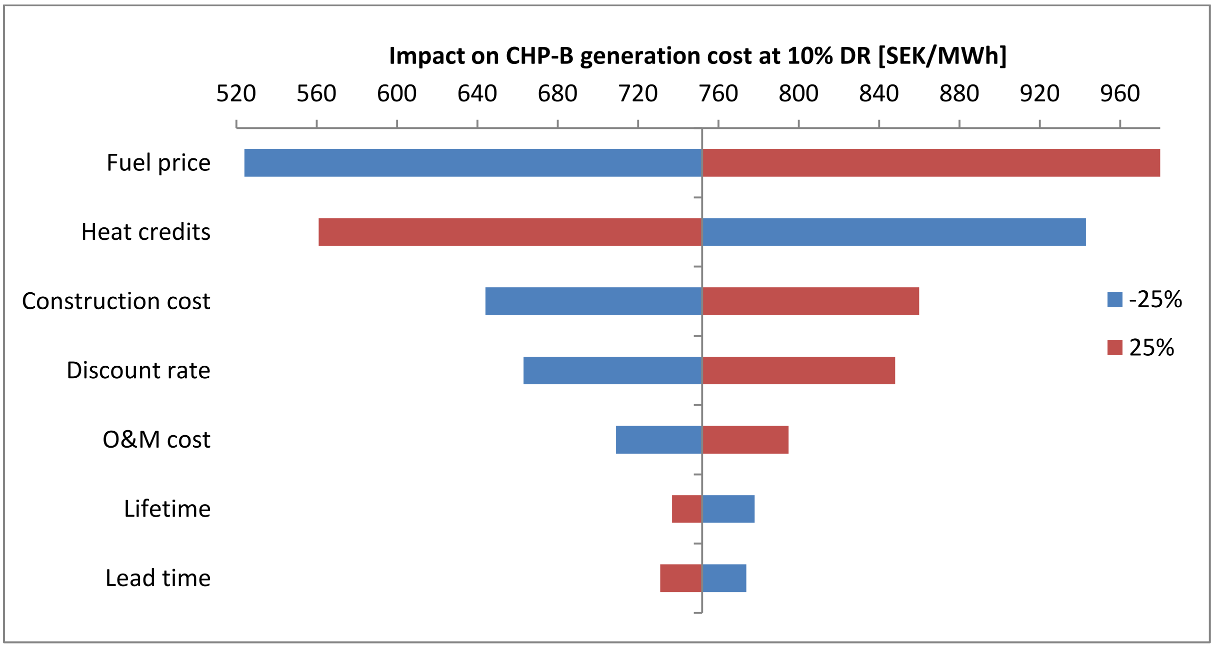


**Figure 28.** CHP-B LCOE sensitivity analysis result.

Figure 28 shows that CHP-B plants seem to be sensitive to changes in multiple parameters. The LCOE is heavily affected by changes in fuel price- and heat credit assumptions. The LCOE is to a large extent also affected by changes in the construction cost and in the discount rate.

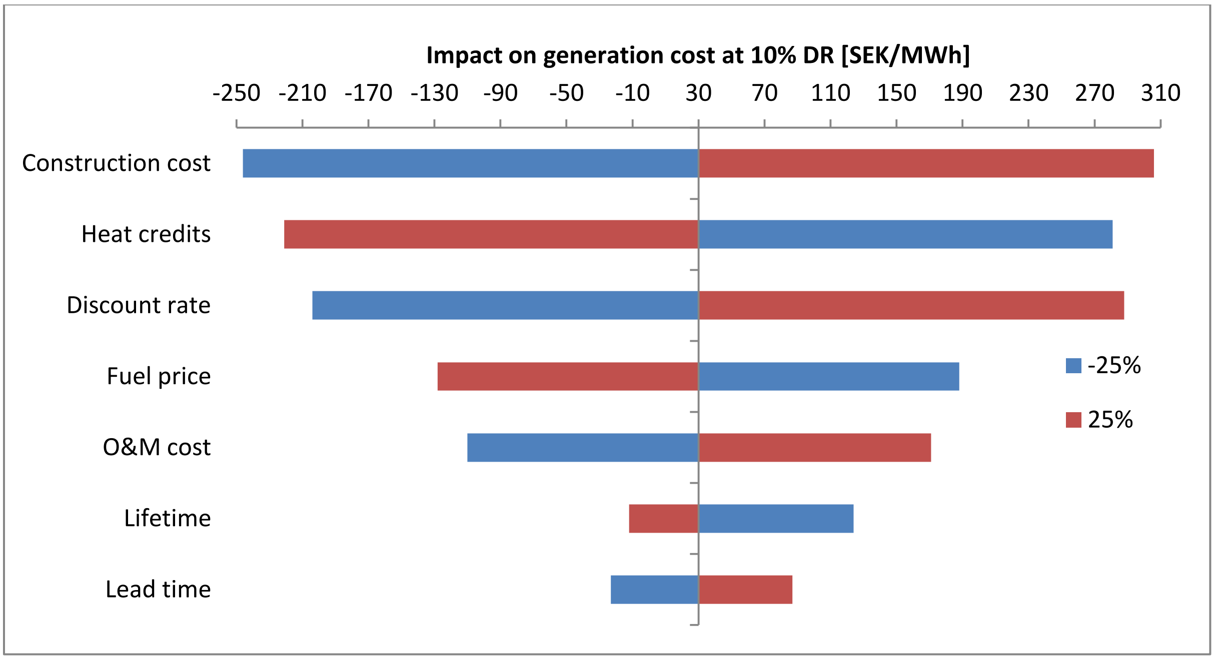


**Figure 29.** CHP-W LCOE sensitivity analysis result.

Figure 29 shows that many parameters have a significant impact on the LCOE result for CHP-W. In fact, CHP-W seems to be the power generating technology sensitive to changes in most input parameters. The LCOE is hugely affected by changes in construction costs, heat credits and in the discount rate, but it is also significantly affected by changes in fuel price and O&M costs. A different assumption on any one of these parameters might therefore have a significant impact on the generation cost result.

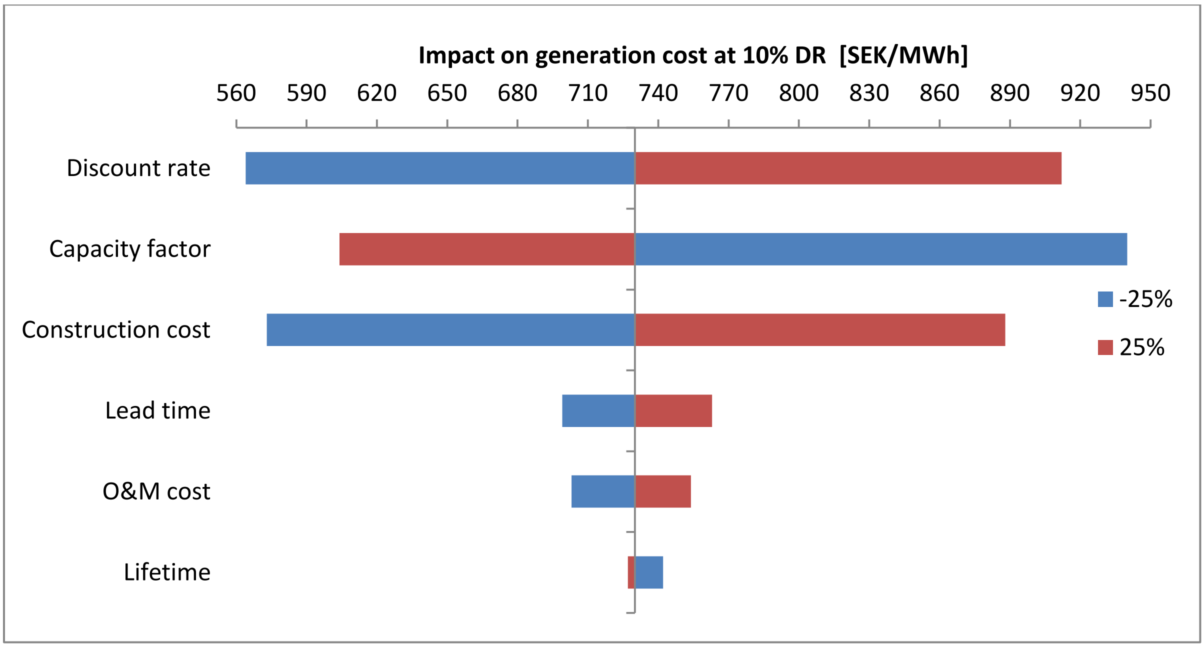


**Figure 30.** Reservoir hydropower LCOE sensitivity analysis result.

Figure 30 shows that reservoir hydro is very sensitive to changes in discount rate, capacity factor and construction cost. The base case assumption on capacity factor is quite low, indicating that reservoir hydro is not used for baseload generation. The LCOE methodology does however fail to account for the load-following ability of hydropower- and other peaking power plants. This topic will be more discussed later on.

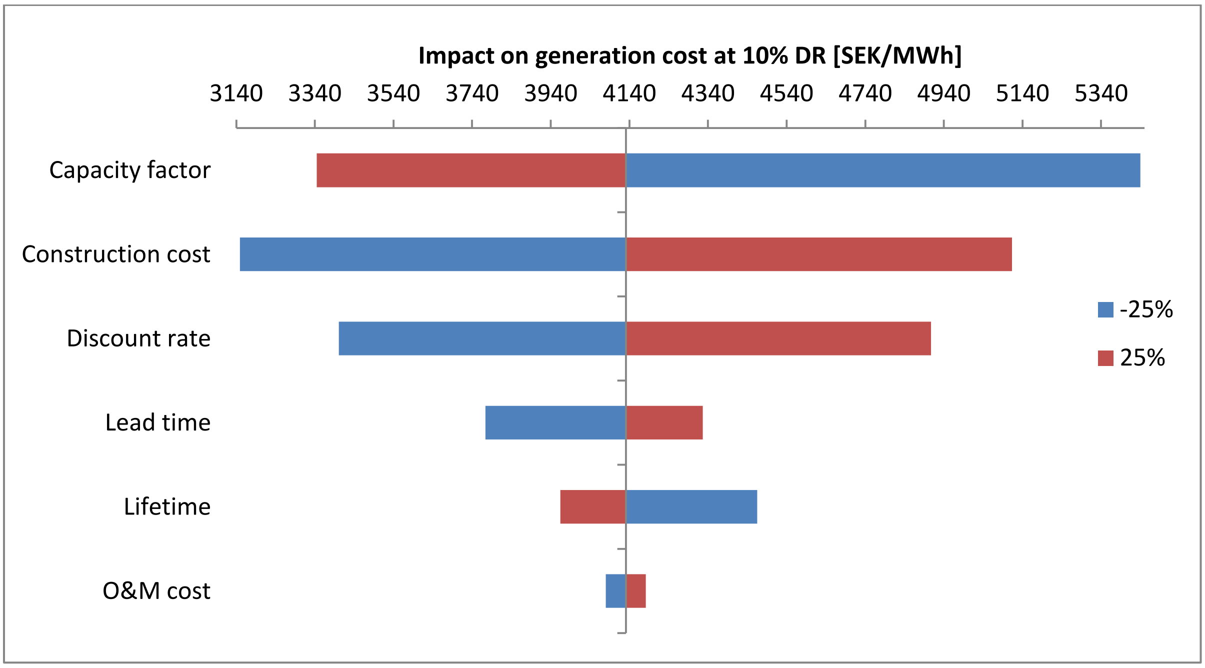


**Figure 31.** PV LCOE sensitivity analysis result.

Figure 31 shows that the generation cost for PV is hugely affected by changes in capacity factor, construction cost, and in the discount rate. The large sensitivity to changes in construction cost and in the capacity factor is interesting as these factors tend to be very site-specific. Take note that the impact of the other parameters is also significant compared to the other power generating technologies.

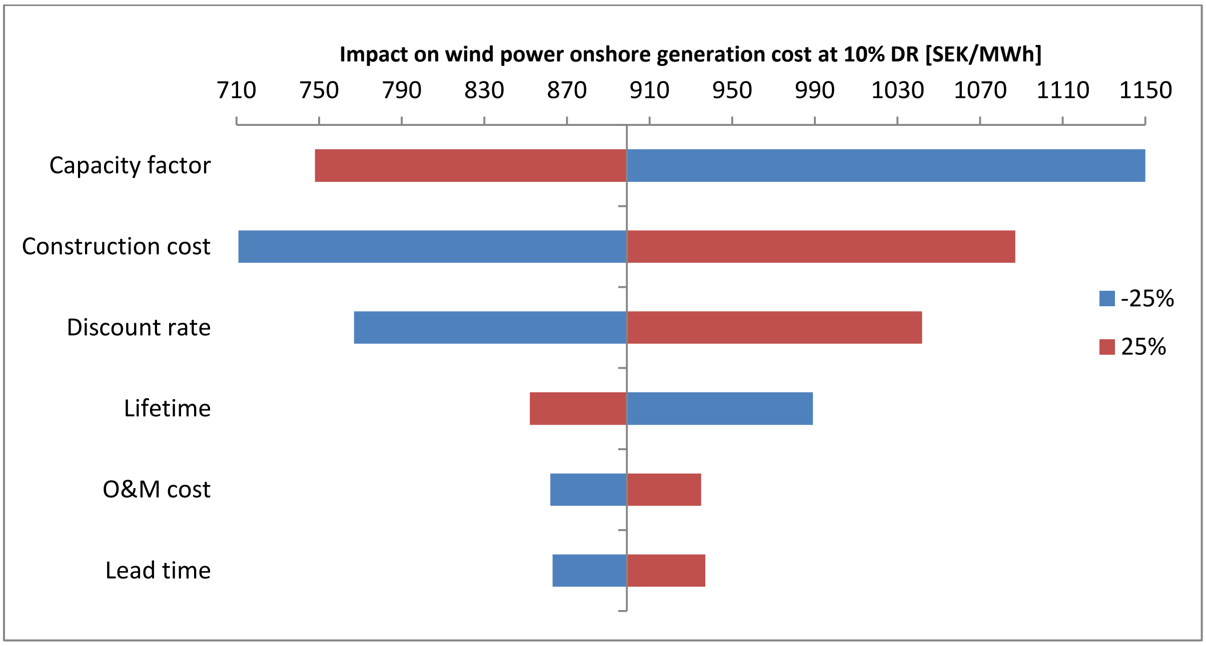


**Figure 32.** Wind power onshore LCOE sensitivity analysis result.

Figure 32 shows the sensitivity for wind power onshore. The generation cost is largely affected by changes in the capacity factor, construction cost and discount rate. The assumption on lifetime is also not insignificant. The site-specific characteristics of wind power is visualised by the significant impact on the generation cost by changes in the capacity factor. Note that the generation cost is more sensitive to a decrease- compared to an increase in the capacity factor.

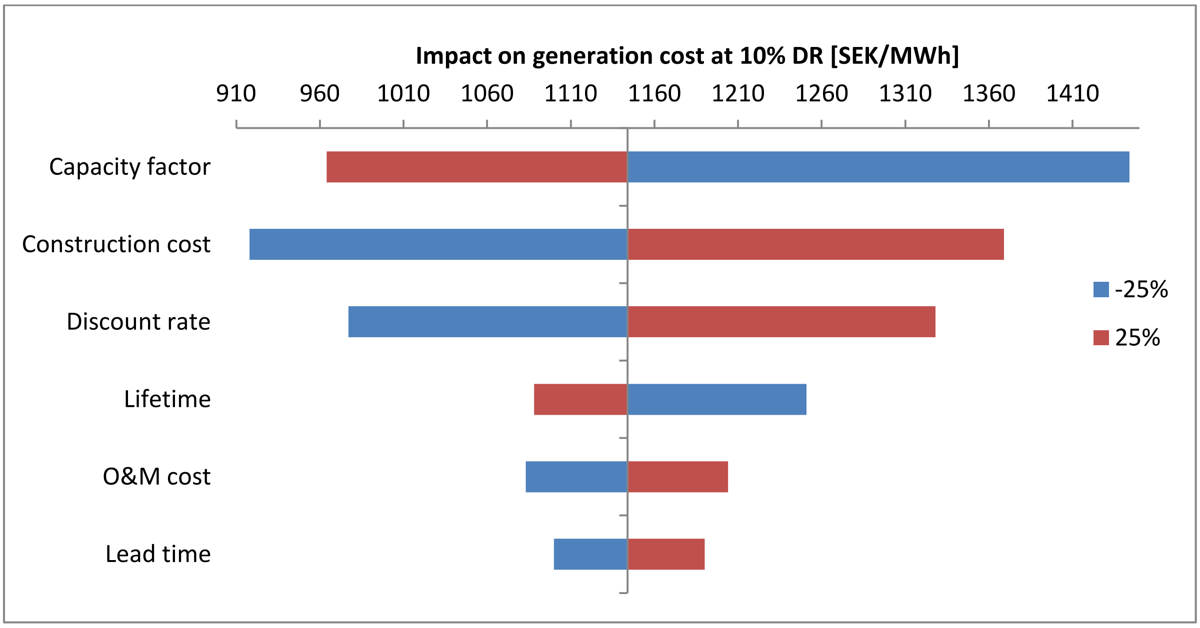


**Figure 33.** Wind power offshore LCOE sensitivity analysis result.

Figure 33 shows that the sensitivity result for wind power offshore is very similar to wind power onshore.

The sensitivity analyses presented above were conducted by changing the input parameters individually. It is however interesting to also change multiple parameters at the same time. Figure 34 shows the impact on the LCOE by changing the four parameters with the biggest impact on the LCOE, indicated by the tornado graphs above, by either +25% or by -25%. Note once again that the capacity factor and the heat credit have a reverse impact on the electricity generation. These parameters are therefore decreased when the other parameters are increased.

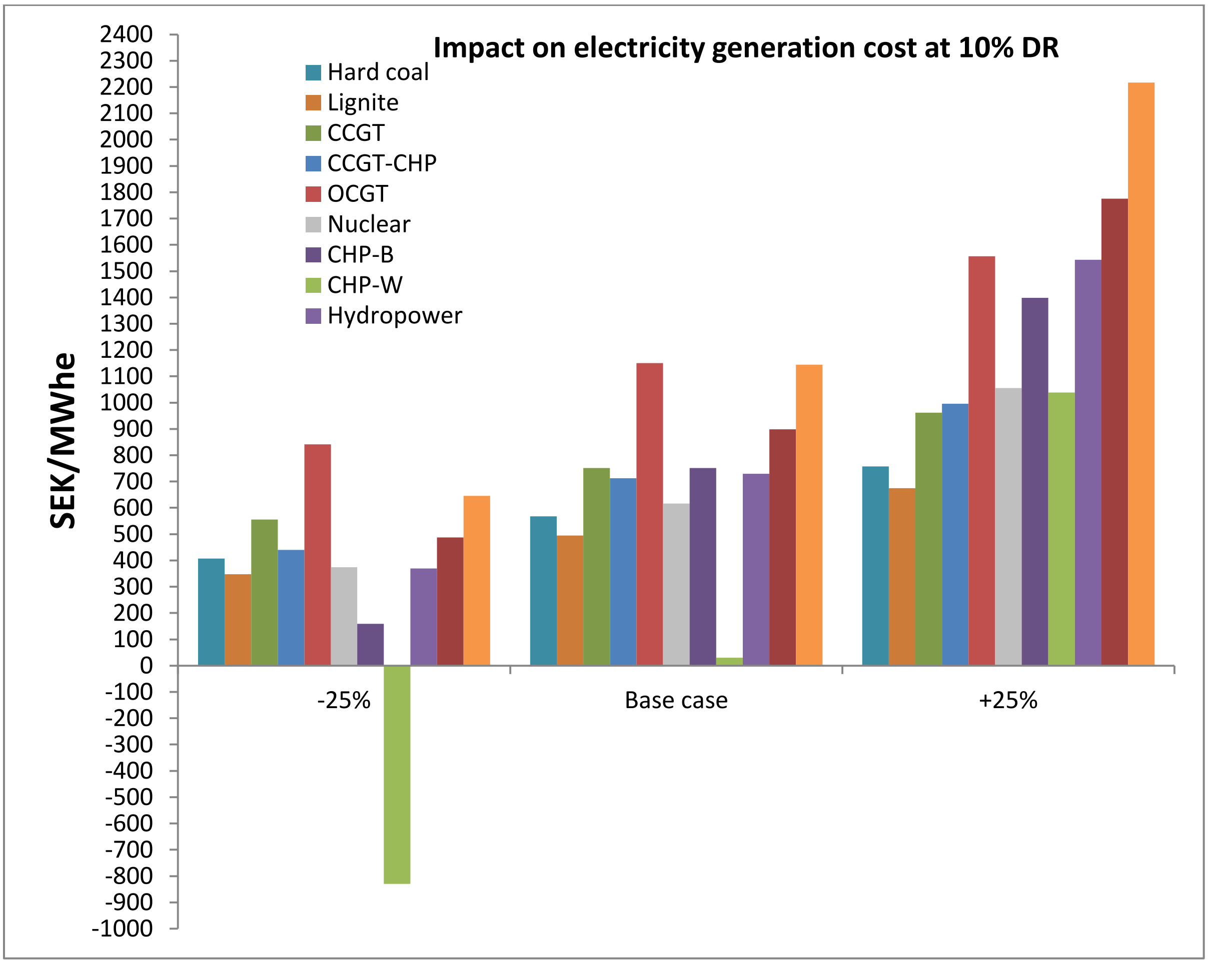


**Figure 34.** Generation cost impact by changes in multiple parameters. The four most sensitive parameters (indicated by the tornado graphs) are changed by either +25% or by -25%. Observe that PV is missing from the figure as the generation cost for PV is big enough to make the figure difficult to read.

The same information as shown in Figure 34 (+ the PV result) is also provided in Table 22.

**Table 22.** Generation cost impact by changes in multiple parameters [SEK/MWh$_e$]. The four most sensitive parameters (indicated by the tornado graphs) are changed by either +25% or by -25%.

| Technology | Change in electricity generation cost | | | Absolute change | |
|---|---|---|---|---|---|
| | -25% | 0 | 25% | -25% | 25% |
| Hards coal | 407 | 568 | 757 | 161 | 189 |
| Lignite | 347 | 495 | 675 | 148 | 180 |
| CCGT-C | 555 | 752 | 962 | 197 | 210 |
| CCGT-CHP | 440 | 712 | 996 | 272 | 284 |
| OCGT | 841 | 1150 | 1556 | 309 | 406 |
| Nuclear power | 374 | 617 | 1056 | 243 | 439 |
| CHP-B | 159 | 752 | 1398 | 593 | 646 |
| CHP-W | -830 | 30 | 1038 | 860 | 1008 |
| Hydropower | 369 | 730 | 1543 | 361 | 813 |
| PV | 2014 | 4131 | 8518 | 2117 | 4387 |
| Wind power onshore | 487 | 899 | 1776 | 412 | 877 |
| Wind power offshore | 646 | 1144 | 2217 | 498 | 1073 |

Some power generating technologies seem much more sensitive to changes in input parameters than others. The coal-fired power plants and CCGT-C are the technologies least affected in this sensitivity analysis (in absolute terms). The impact on PV is extreme, but CHP-W and wind power also display generation cost changes as large as 900-1000 SEK/MWh$_e$ under the prevailing conditions. The impact on CHP-B and hydropower is also significant.

### 4.2.2 Impact of changes in the discount rate

The impact on the electricity generation cost by varying the discount rate from 0%-15% is presented in Figure 35. Note that the figure shows the relative change (with the 0% generation cost as base) in the generation cost and not the absolute change.

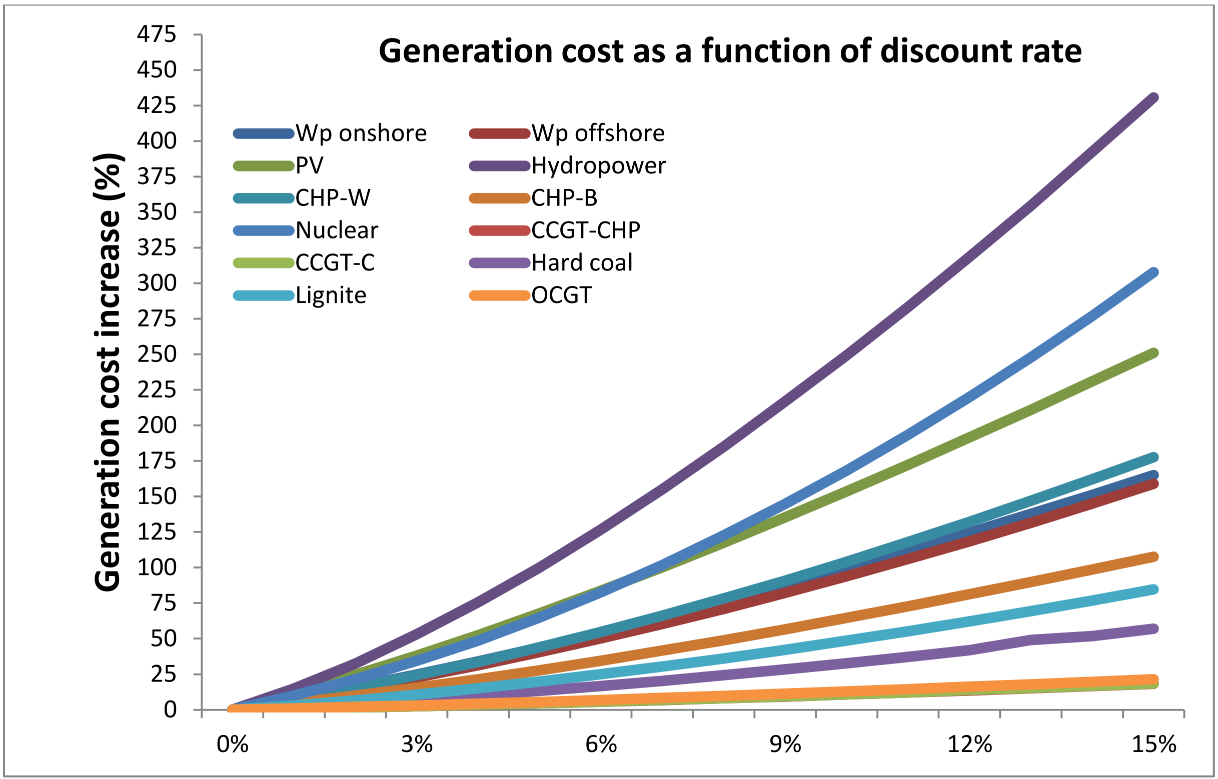


**Figure 35.** Generation cost as a function of discount rate.

OCGT and CCGT-C power plants seem insensitive to changes in the discount rate, while hydropower, PV and nuclear power plants are largely affected by discount rate increases. The impact on the technologies in between is however not insignificant.

### 4.2.3 Impact of changes in the capacity factor

Section 4.2.1 has shown that the costs for intermittent power generating technologies are sensitive to changes in the capacity factor. This section will highlight this fact, but it will also visualise the impact on the power generating technologies assumed as operating in baseload, with a base case assumption of ~0.8-0.85 capacity factor.

The impact of assuming that CHP power plants only operate during the heating season, instead of the base case assumption on baseload operation, will also be illustrated.

The impact on the electricity generation cost for the baseload power generating technologies is presented in Figure 36. The capacity factor is varied from 0.75 to 0.95, with a base case assumption of 0.85.

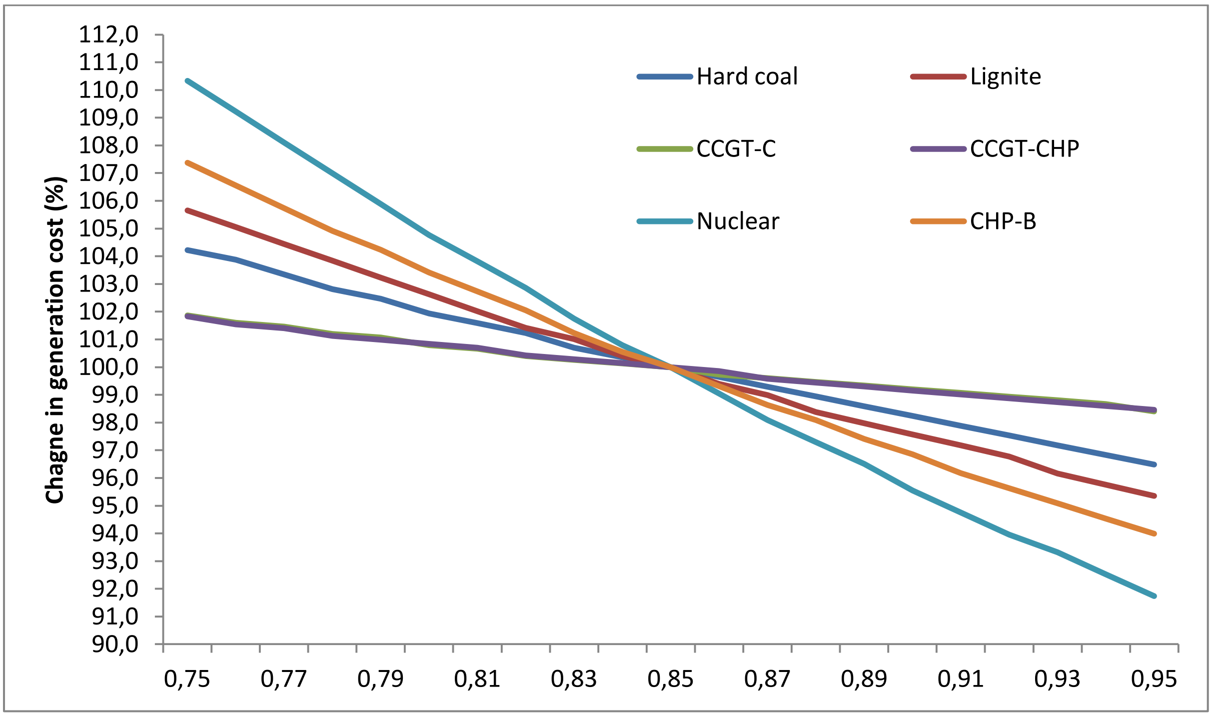


**Figure 36.** Capacity factor sensitivity analysis (base-load power generating technologies).

The gas-fired stations are very resistant to changes in the capacity factor. The coal-fired power plants are moderately affected, while CHP-B- and nuclear power plants are the most sensitive technologies. The capacity factors are supposed to be average values valid for the entire lifetime of the power plant. A capacity factor of 0.75 or 0.95 might therefore be an unrealistic assumption in some cases.

Elforsk (2011b) assumes that the CHP plants (excluding CHP-W) only operates during the heating season. This is a good point and something worth to bear in mind when evaluating the electricity generation cost for CHP plants. The electricity generation cost difference by assuming baseload operation, 0.85 capacity factor, vs. heating-season operation, 0.57 capacity factor, ~5000 full load hours, is visualised in Table 23.

**Table 23.** Impact on CHP generation cost by assuming base-load vs. heating-season operation [SEK/MWh$_e$].

| Technology | Generation cost at 0,85 CF | Generation cost at 0,57 CF | Change in generation cost |
|---|---|---|---|
| CCGT-CHP | 712 | 760 | 48 |
| CHP-B | 732 | 933 | 201 |
| CHP-W | -48 | 456 | 504 |

The generation cost for CCGT-CHP is virtually not affected by the large decrease in the capacity factor. The impact on CHP-B and CHP-W is however significant, especially when considering the CHP-W power plant. This impact is very important to bear in mind, especially when comparing different electricity generation cost assessments with each other.

Figure 37 illustrates how sensitive intermittent power generating technologies are to changes in the capacity factor. The figure shows relative changes from an assumed starting position. The capacity factor interval for wind power is 0.2-0.4, with initial position at 0.3. The same assumptions for PV are 0.05-0.25 and 0.15.

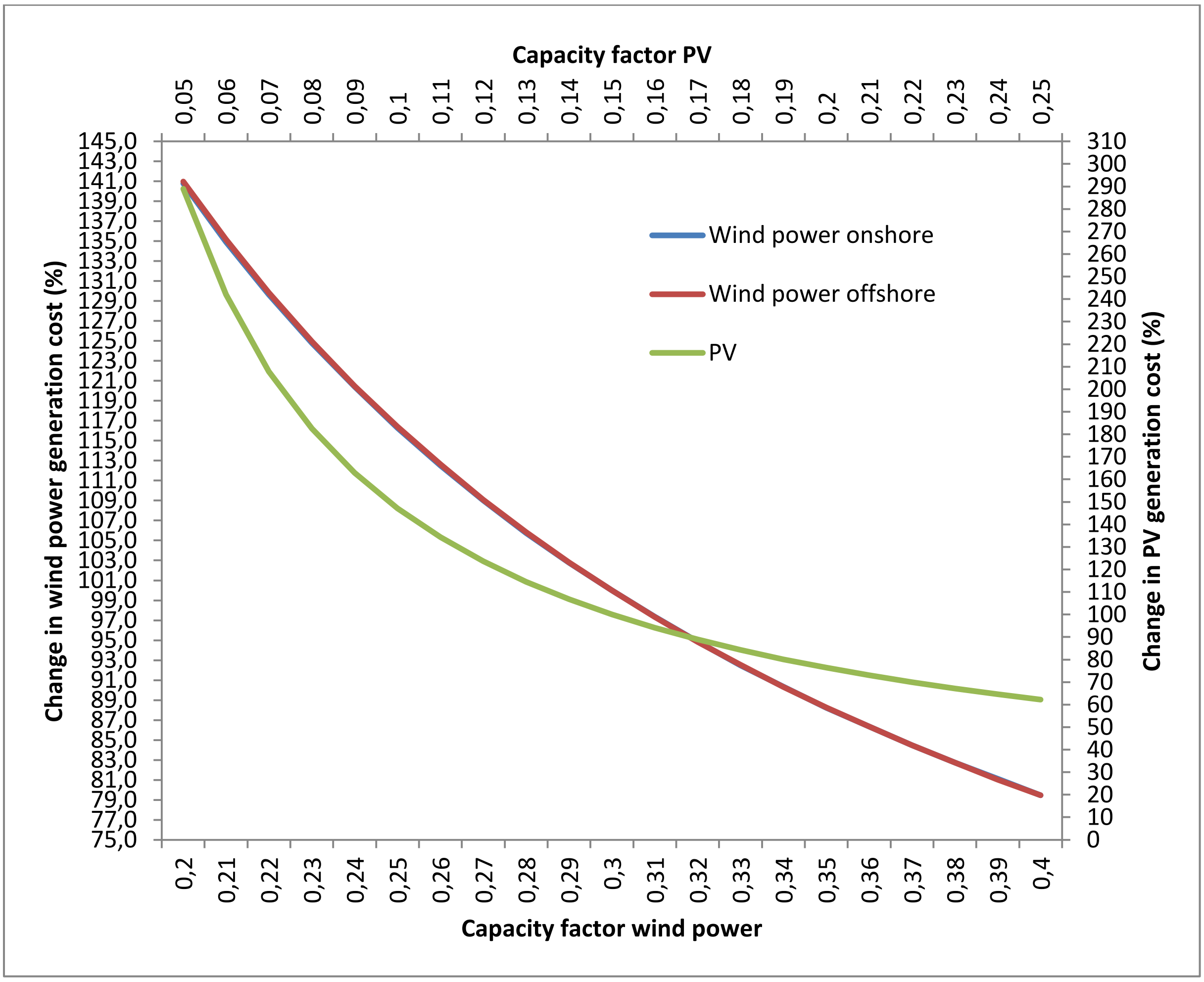


**Figure 37.** Capacity factor sensitivity analysis (intermittent power generating technologies).

The intermittent power generating technologies are very sensitive to changes in the capacity factor. Note also that the generation cost difference is much more pronounced when the capacity factor is decreased compared to when it is increased.

### 4.2.4 Impact of using overnight- vs. total investment cost (including the IDC)

The interest expenses occurred during the construction phase of a power plant can be quite significant when assuming long lead times and high interest rates.

Table 24 shows the impact on the LCOE by using only overnight investment costs or by also including the IDC expenses. The assumptions on lead time, DR and cost outlay corresponds to the base case setup (Appendix I).

**Table 24.** Generation cost using overnight- vs. IDC investment cost (10% DR).§

| Technology | Generation cost using overnight construction costs [SEK/MWh] | Generation cost including IDC [SEK/MWh] | Difference [%] |
|---|---|---|---|
| Wp on | 798 | 899 | 13 |
| Wp off | 985 | 1144 | 16 |
| PV | 3774 | 4131 | 9 |
| Hp | 594 | 730 | 23 |
| CHP-W | -164 | 30 | 118 |
| CHP-B | 694 | 752 | 8 |
| Nuclear | 477 | 617 | 29 |
| CCGT-CHP | 694 | 712 | 3 |
| CCGT-C | 733 | 752 | 3 |
| Hard coal | 528 | 568 | 8 |
| Lignite | 449 | 495 | 10 |
| OCGT | 1125 | 1150 | 2 |

The difference in generation cost is significant for nuclear power, CHP-W and hydropower, and not extraneous for wind power, PV, and coal condensing power plants. Only using overnight investment costs can therefore lead to significantly lower generation cost figures for some power generating technologies.

### 4.2.5 Impact of carbon emission costs

The *European Union Emissions Trading System* (EU ETS) is a vital part in EU climate policy and an example of a big international scheme to reduce the emissions of greenhouse gases. Power plants, factories and other installations in the system are assigned a limit of the total amount of greenhouse gases that they are allowed to emit. The affected companies receive emission allowances that they can sell or buy from each other when needed. There is a limit to the number of allowances which ensures that they have a value. At the end of each year each company has to surrender enough allowances to cover the greenhouse gas emissions. If not, fines are imposed ((European Commission, 2010). The impact on the LCOE by different assumptions on carbon emission costs is visualised in Table 25. This is a simple approach but it is useful in showing the impact of climate policy actions on the LCOE from fossil-fuelled technologies.

**Table 25.** Impact of changes in the carbon emission costs [10% DR]

| Carbon emission cost [SEK/tonne] | Generation cost [SEK/MWhe] | | | |
|---|---|---|---|---|
| | Hard coal | Lignite | CCGT | CCGT-CHP |
| 0 | 440 | 352 | 691 | 636 |
| 100 | 514 | 434 | 726 | 680 |
| 200 | 588 | 517 | 761 | 724 |
| 300 | 662 | 600 | 796 | 768 |

Coal power plants are very competitive in the absence of carbon emission costs. Including such costs can however have significant impacts on the LCOE result. The impact on the gas-fired stations are not as pronounced as for the coal-fired alternatives, but high assumptions still lead to significantly higher generation costs. The big impact of carbon emission costs on electricity generation costs is important to keep in mind as there is a great deal of uncertainty in what price to choose and if such costs should be included in the assessments or not.

### 4.2.6 Comparison of using constant vs. increasing fuel- and carbon cost

Some of the reviewed studies assume that fuel prices are constant in time. Others try to estimate how the fuel prices evolve during a given time period. Figure 38 illustrate the impact on the LCOE by assuming constant- or yearly increasing real fuel prices of 1%-5%. 0% price increase corresponds to the base case assumption on constant fuel prices. The base case generation cost is normalised to 100. The same approach is used in Figure 39, showing the impact of increasing carbon emission price on the LCOE.

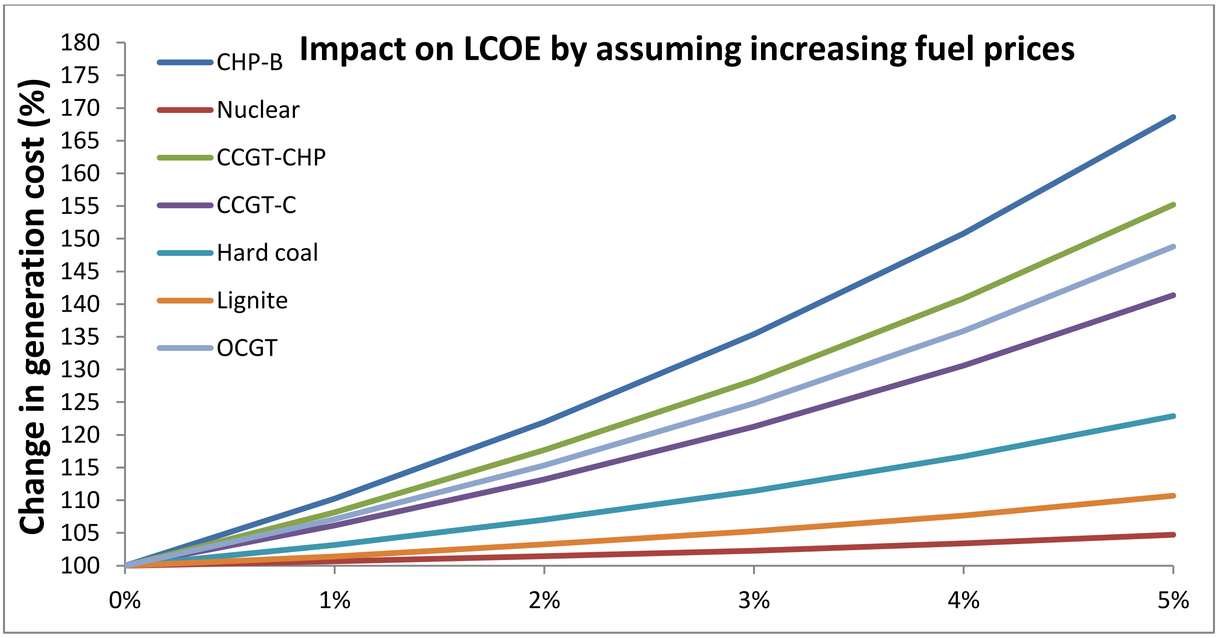


**Figure 38.** Impact on LCOE by assuming increasing fuel prices. The fuel price for CHP-W is assumed as negative and a fuel price increase would therefore lead to lower generation costs. CHP-W is therefore excluded from the figure.

The LCOE for CHB-B and the gas-fired technologies is heavily affected by assumptions on increasing fuel prices. Coal-fired stations and nuclear power are much more resistant. A 4%-5% yearly real price increase is a big figure, but as Figure 38 shows, the generation cost for

CHP-B increases by 35% if we assume a 3% yearly real fuel price increase and by 22% if we assume a 2% yearly increase. The LCOE for the gas-fired stations shows similar results but not as pronounced as for CHP-B. An assumption on increasing fuel prices might certainly be significant enough to change the relative rankings of different power generating technologies.

Figure 39 shows that the carbon price increases have to be significant in order to have a big impact on the LCOE result. Observe that a higher assumption on carbon emission cost in the base case would lead to a larger impact of increasing costs.

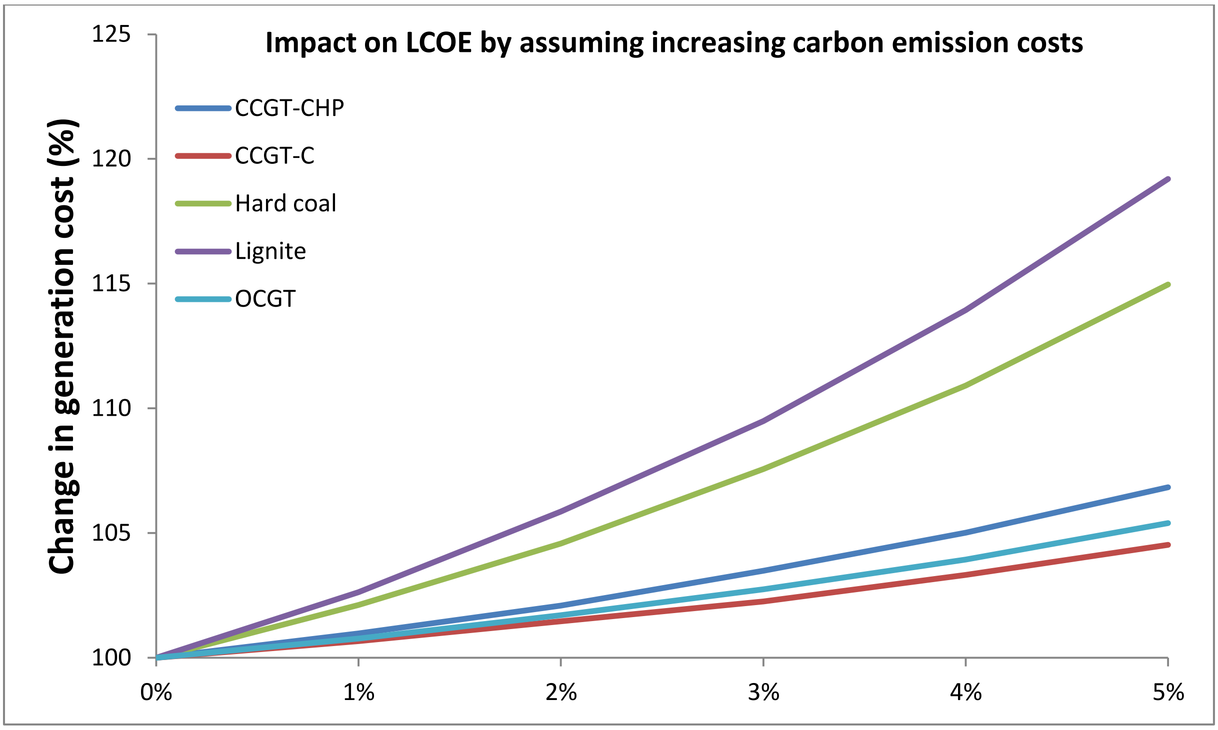


**Figure 39.** Impact on LCOE by assuming increasing carbon emission costs.

# 5 Another perspective from looking at expected revenue

The reviewed studies focuses on calculating the levelised electricity generation costs, i.e. the ratio of total lifetime expenses to the total expected electricity output expressed in present values. The result will be equivalent to the average electricity price that would have to be paid by the consumers to exactly repay the investor for the power plants lifetimes expenses (including the required rate of return on the investment).

The Swedish electricity market was liberalised in 1996. Until then, the electricity market was regulated and the producers were to some extent bound to invest in new power generating capacity. Nowadays production is no longer regulated and investment decisions are taken on purely economic grounds. Simply speaking, investments will take place if the expected return on a specific project is higher than the expected return on alternative investments (Energimarknadsinspektionen, 2007). The deregulation of the electricity market has in this sense put more focus on revenue maximising rather than cost minimizing.

This chapter provides a profitability evaluation of a set of different power generating technologies, i.e. focus is not only on costs but also on revenues. The evaluation is done by implementing a model based on the general discounted cash flow (DCF) methodology. The approach is similar to the LCOE methodology, but the model also account for revenues in form of electricity- and heat sales. The model is simple and does not account for e.g. taxes and subsidies. The model calculates the payback period, the net present value and the discounted payback period given a set of input parameters.

The input parameters (investment costs, O&M costs, capacity factor, etc.) are taken from Elforsk (2011b). The reason is that electricity generation costs seem to be both time- and country specific (see chapter 7). The Elforsk study is therefore best at reflecting current Swedish (and maybe also Nordic) conditions. The input parameters are all taken from the stations with largest net electricity output. Economies of scale are also an important factor when it comes to electricity generation costs (see chapter 7). This economic valuation should however not be used as a reference to the actual economic profitability of a given power generating technology. The assumptions on input parameters are presented in Table 26.

**Table 26.** Input parameters DCF model.

| Input parameter | Hard coal | CCGT-C | CCGT-CHP | Nuclear | CHP-B |
|---|---|---|---|---|---|
| Net el power [MW] | 740 | 420 | 150 | 1600 | 80 |
| Net el efficiency (LHV) [%] | 46 | 58 | 50,5 | 36 | 30,9 |
| Net thermal efficiency [%] | | | 92 | | 108 |
| Net heat power [MW] | | | 123 | | 200 |
| Capacity factor | 0.78 | 0.78 | 0.56 | 0.87 | 0.55 |
| Lifetime [years] | 25 | 25 | 25 | 40 | 25 |
| Discount rate | 5-10% | | | | |
| Overnight cost [SEK/kWe] | 14500 | 7000 | 9500 | 28000 | 25500 |
| O&M cost [SEK/MWhe] | 58 | 46 | 57 | 100 | 159 |
| Fuel price [SEK/MWhf] | 90 | 250 | 250 | 14 | 210 |
| Heat credits | 232 SEK/MWhh | | | | |
| Construction period | 3 | 3 | 3 | 6 | 3 |
| Interest during construction | Same as the discount rate (for all technologies) | | | | |
| Cost outlay during construction | linear | | | | |
| | CHP-W | HP | PV | WP on | Wp off |
| Net el power [MW] | 20 | 90 | 0,95 | 60 | 375 |
| Net el efficiency (LHV) [%] | 19 | - | - | - | - |
| Net thermal efficiency [%] | 99 | | | | |
| Net heat power [MW] | 84 | | | | |
| Capacity factor | 0.76 | 0.46 | 0.12 | 0.38 | 0.39 |
| Lifetime [years] | 25 | 40 | 15 | 20 | 20 |
| Discount rate | 5-10% | | | | |
| Overnight cost [SEK/kWe] | 77000 | 19000 | 50000 | 15000 | 25000 |
| O&M cost [SEK/MWhe] | 609 | 13 | 300 | 140 | 200 |
| Fuel price [SEK/MWhf] | -120 | - | - | - | - |
| Heat credits | 232 SEK/MWhh | | | | |
| Construction period | 3 | 4 | 1 | 2 | 3 |
| Interest during construction | Same as the discount rate (for all technologies) | | | | |
| Cost outlay during construction | linear | | | | |

The purpose of the DCF model is to provide a simplified picture of how a given power plant performs under market conditions. As stated in the beginning of this section, in deregulated electricity markets focus is not on cost minimizing but on revenue maximizing. Different power plants exhibit different economic profitability due to the differences in the market value of the electricity that they supply. This aspect is not captured by the LCOE methodology.

The biggest challenge is to assume reasonable electricity- and heat prices. The base case electricity price assumption is based on the 2010 Nord Pool Spot prices in Sweden. 2010 was chosen because it was the last year before the Swedish electricity market was divided into 4 different bidding areas.

Figure 40 shows a price duration curve constructed on basis of the average weekly 2010 Nord Pool Spot prices (Nord Pool Spot, 2012). This curve has been used to set up a simple assumption on a peak-, intermediate- and a baseload electricity price. The peak price has been constructed by taking the average value of the six weeks with the highest reported values, the intermediate price in based on the following eight weeks, and the baseload price is the remainder. This simple approximation yields the results presented in Table 27.

**Table 27.** Assumption on electricity price used in the DCF model.

| | Hours | Electricity prise [SEK/MWhe] |
|---|---|---|
| Peak load | 1008 | 1006 |
| Intermediate load | 1344 | 684 |
| Baseload | 6408 | 442 |
| Average electricity price | 8760 | 544 |

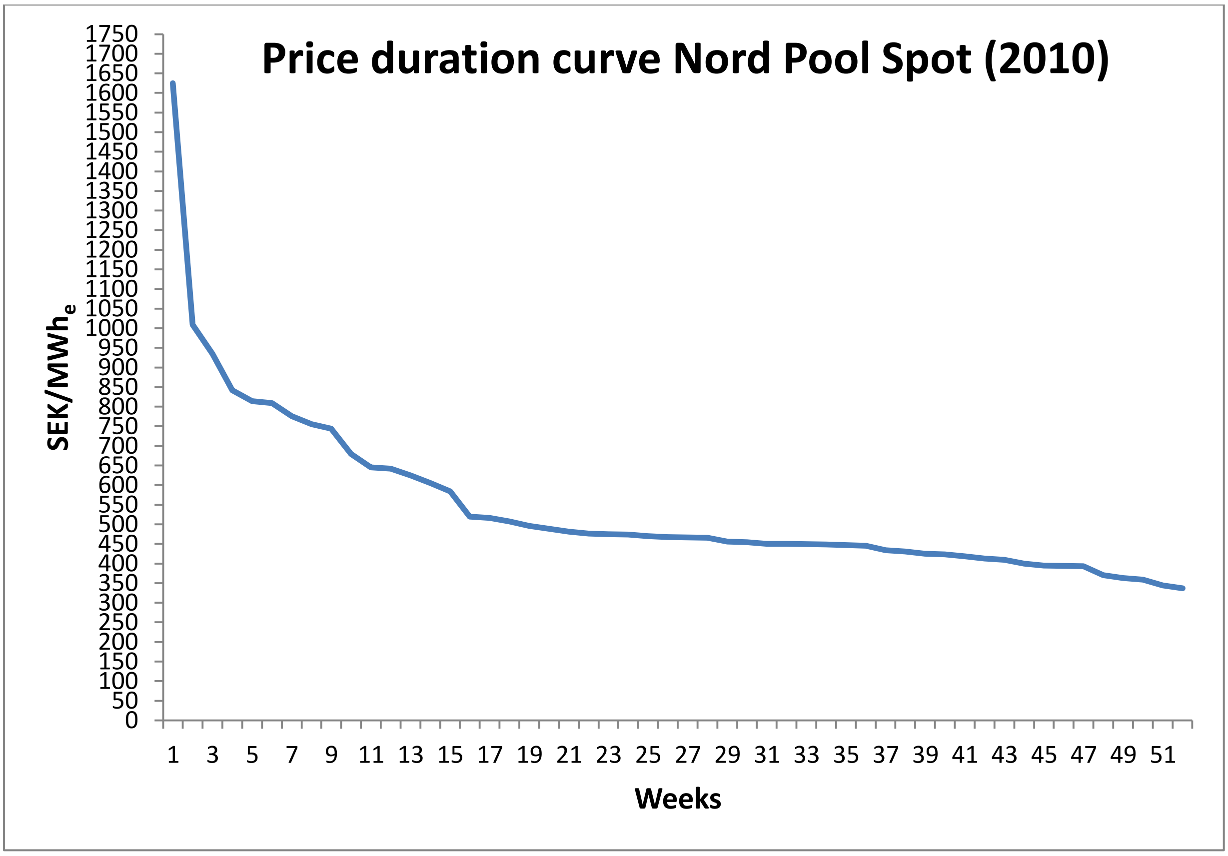


**Figure 40.** Price duration curve Nord Pool Spot.

Economic indicators provided are the payback period, the net present value and the discounted payback period. These are presented below.

- Payback period (PP)

The payback period is the length of time required to recover the initial cost a project. It is an important indicator of a project's viability as longer payback periods are not desirable for an investment decision (Investopedia, 2012e). The payback period is calculated as

$$PP = \frac{investment\ cost\ (including\ IDC)}{Annual\ cash\ inflows}$$

The payback period ignores the decreasing value of money over time due to discounting. This impact will be tested by the net present value and the discounted payback period indicators.

- Net present value (NPV)

The NPV is the difference between the present value of all cash inflows and the present value of all cash outflows. It is calculated with

$$NPV = \sum_{t=0}^{T} \frac{C_t}{(1+r)^t} - C_0$$

$C_t$ is net cash flow, $C_0$ is the initial investment (including IDC), and r is the discount rate.

If the NPV is positive it means that the value of the project is positive and the investment could be undertaken. A negative NPV indicates that the project should be abandoned (Investopedia, 2012d).

- Discounted payback period (DPP)

The discounted payback period is similar to the payback period, but it accounts for the discounted value of money over time. The discounted payback period is a good complement to the NPV as it shows the number of years required to breakeven. This may be more intuitive than the figure NPV provides. Projects with a negative net present value will not have a discounted payback period as the initial cost never will be recovered (Investopedia, 2012b).

## 5.1 Results using constant prices

This section presents evaluation results by assuming a constant electricity price, heat price, fuel price, O&M cost, and carbon emission cost throughout the power plants lifetime. This is a simple approach, but making good assumptions on future prices are also very difficult. This section removes this uncertainty. The discounted payback time is found by plotting the cumulative discounted cash flow (CDF) vs. time. The discounted payback period is equal to the point in time where the CDF becomes positive. This is visualised by Figure 41, showing the discounted payback period (approximately 24 years) for a hard coal power plant at 5% DR. The net present value is calculated by using Microsoft Excel's built-in NPV function.

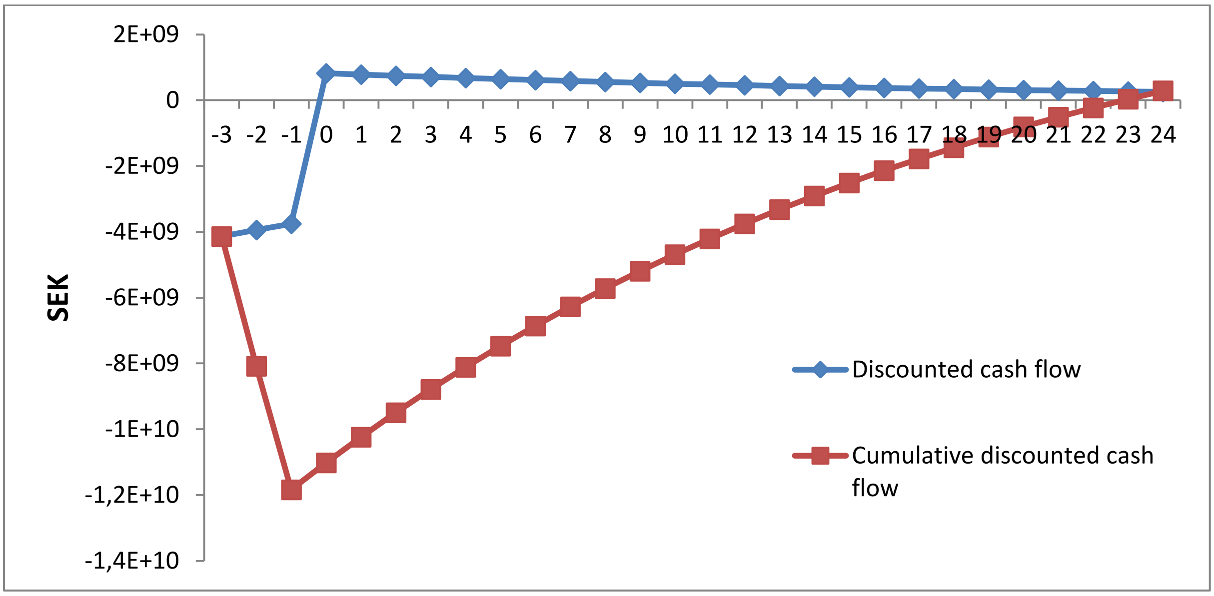


**Figure 41.** Discounted payback period hard coal (5% DR).

The economic indicators are presented in Table 28 and in Table 29, with an assumed discount rate of 5%, respectively 10%.

**Table 28.** Economic indicators at 5% DR.

| Technology | Payback period [years] | Discounted payback period [years] | NPV [SEK/kWe] |
|---|---|---|---|
| Hard coal | 7.3 | 10 | 13 400 kr |
| CCGT-C | 15.3 | - | -1 000 kr |
| CCGT-CHP | 10.6 | 17.0 | 2 700 kr |
| Nuclear | 9.1 | 15.0 | 22 300 kr |
| CHP-B | 18.5 | - | -7 800 kr |
| CHP-W | 7.5 | 10.0 | 66 900 kr |
| Hp | 8.9 | 13.5 | 17 100 kr |
| Pv | 195.0 | - | -2 600 kr |
| Wp on | 11.2 | 17.5 | 1 500 kr |
| Wp off | 21.3 | - | -12 200 kr |

**Table 29.** Economic indicators at 10% DR.

| Technology | Payback period [years] | Discounted payback period [years] | NPV [SEK/kWe] |
|---|---|---|---|
| Hard coal | 7.3 | 17.5 | 2 200 kr |
| CCGT-C | 15.3 | - | -3 900 kr |
| CCGT-CHP | 10.6 | - | -2 600 kr |
| Nuclear | 9.1 | - | -6 400 kr |
| CHP-B | 18.5 | - | -17 200 kr |
| CHP-W | 7.5 | 19.0 | 9 000 kr |
| Hp | 8.9 | - | -1 200 kr |
| Pv | 195.0 | - | -2 800 kr |
| Wp on | 11.2 | - | -4 700 kr |
| Wp off | 21.3 | - | -19 300 kr |

It is easy to see the major impact the discount rate has on the economic viability of the projects. The only power stations that prevail under the assumed conditions are the hard coal power plant and the CHP-W installation.

The evaluation is carried by using a simple model that does not account for taxes, subsidies and other factors met by investors. Despite this, the evaluation shows that (real) electricity prices might have to be higher than present day figures in order to motivate investments in new generating capacity.

This study does not account for taxes and subsidies. Such parameters might however have a significant impact on the economic profitability of a power plant. The impact on the economic indicators by including electricity certificate incomes and carbon emission expenses will therefore be visualised below.

Swedish CHP-B plants, PV installations and wind power plants are entitled to an electricity certificate for every MWh of electricity they produce over a period of 15 years (Swedish Energy Agency, 2011). The electricity certificates are an important source of income for renewable power plants. Figure 42 shows the price trend in electricity certificates prices since 2006. A few years ago the price was over 300 SEK/MWh$_e$, but the trend since then has been on falling prices.

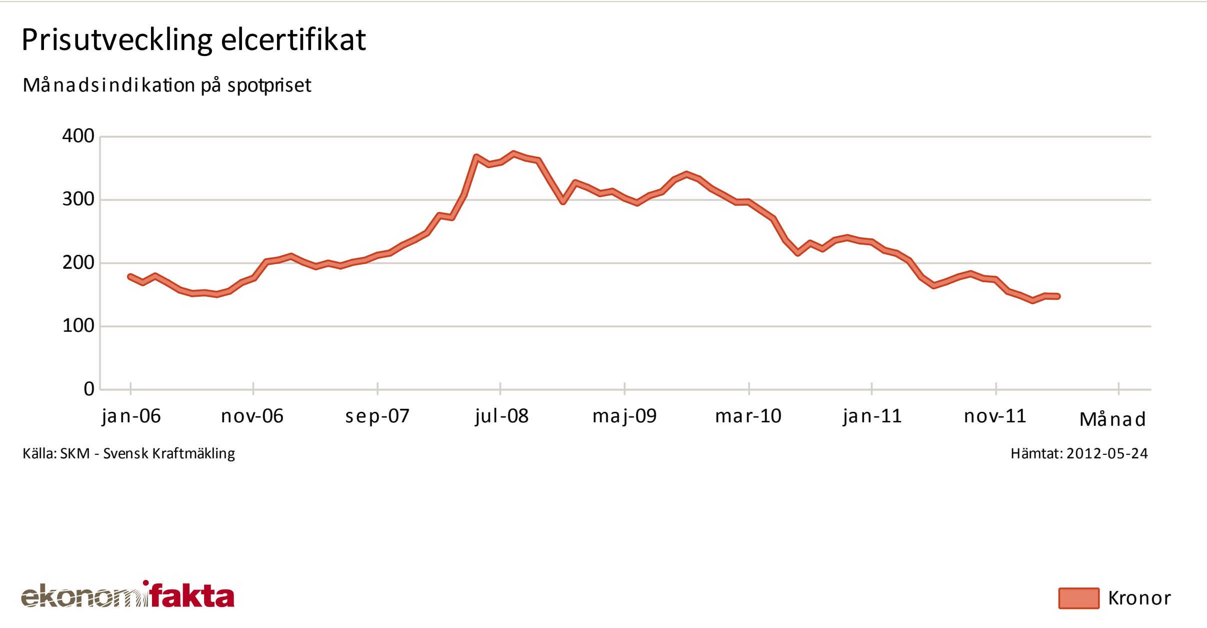


**Figure 42.** Price trend electricity certificates (Ekonomifakta, 2012). The y-axis shows the price in SEK/MWh$_e$.

The impact of electricity certificates on the economic indicators for wind power and CHP-B is visualised in Table 30. The impact on PV is not displayed as any reasonable assumption on electricity certificate price will not be high enough to make PV economically viable under current conditions. 207 SEK/MWh was the price paid in April 2012 (Svenska Kraftnät, 2012).

**Table 30.** Impact of electricity certificates on the economic indicators.

| Technology | 207 SEK/MWh | | 100 SEK/MWh | | 0 SEK/MWh | | 300 SEK/MWh | |
|---|---|---|---|---|---|---|---|---|
| 5% DR | PP | DPP | PP | DPP | PP | DPP | PP | DPP |
| Wp on | 7.4 | 10.0 | 8.9 | 12.5 | 11.2 | 17.5 | 6.4 | 8.0 |
| Wp off | 13.3 | - | 16.5 | - | 21.3 | - | 11.4 | - |
| CHP-B | 10.7 | 18.0 | 13.7 | - | 18.5 | - | 9.0 | 13.5 |
| 10% DR | | | | | | | | |
| Wp on | 7.4 | 16.0 | 8.9 | - | 11.2 | - | 6.4 | 11.5 |
| Wp off | 13.3 | - | 16.5 | - | 21.3 | - | 11.4 | - |
| CHP-B | 10.7 | - | 13.7 | - | 18.5 | - | 9.0 | - |
| | NPV | | NPV | | NPV | | NPV | |
| 10% DR | | | | | | | | |
| Wp on | 9 000 kr | | 5 100 kr | | 1 500 kr | | 12 300 kr | |
| Wp off | -4 500 kr | | -8 500 kr | | -12 200 kr | | -1 000 kr | |
| CHP-B | 3 600 kr | | -2 300 kr | | -7 800 kr | | 8 700 kr | |
| 10% DR | | | | | | | | |
| Wp on | 1 000 kr | | -1 900 kr | | -4 700 kr | | 3 600 kr | |
| Wp off | -13 400 kr | | -16 500 kr | | -19 300 kr | | -10 800 kr | |
| CHP-B | -8 600 kr | | -13 100 kr | | -17 200 kr | | -4 800 kr | |

The profitability stands and falls with the income from electricity certificates sales. Current price drop on electricity certificates is therefore bound to have a negative impact on investments in wind power and biomass power plants. Investments based on evaluations assuming high electricity certificate prices might therefore be facing profitability issues.

Table 31 shows that assumptions on carbon dioxide emission costs have a significant negative economic impact on the economic indicators for the fossil-fuelled technologies. The assumptions on carbon dioxide emissions are the same as used in the sensitivity analysis (Appendix I).

**Table 31.** Impact of carbon emission costs on the economic indicators.

| Technology | 173 SEK/MWh | | 100 SEK/MWh | | 0 SEK/MWh | | 300 SEK/MWh | |
|---|---|---|---|---|---|---|---|---|
| 5% DR | PP | DPP | PP | DPP | PP | DPP | PP | DPP |
| Hard coal | 13.1 | 24.5 | 9.8 | 15.0 | 7.3 | 10.0 | 31.2 | - |
| CCGT | 153.3 | - | 31.9 | - | 15.3 | - | -27.3 | - |
| CCGT-CHP | 17.1 | - | 13.6 | - | 10.6 | 16.5 | 31.2 | - |
| 10% DR | | | | | | | | |
| Hard coal | 13.1 | - | 9.8 | - | 7.3 | 17.0 | 31.2 | - |
| CCGT | 153.3 | - | 31.9 | - | 15.3 | - | -27.3 | - |
| CCGT-CHP | 17.1 | - | 13.6 | - | 10.6 | - | 31.2 | - |
| | NPV | | NPV | | NPV | | NPV | |
| 5% DR | | | | | | | | |
| Hard coal | 400 kr | | 5 900 kr | | 13 400 kr | | -9 100 kr | |
| CCGT | -7 000 kr | | -4 500 kr | | -1 000 kr | | -11 500 kr | |
| CCGT-CHP | -2 300 kr | | -200 kr | | 2 700 kr | | -6 000 kr | |
| 10% DR | | | | | | | | |
| Hard coal | -6 500 kr | | -2 800 kr | | 2 200 kr | | -13 000 kr | |
| CCGT | -8 000 kr | | -6 300 kr | | -3 900 kr | | -11 100 kr | |
| CCGT-CHP | -6 000 kr | | -4 600 kr | | -2 600 kr | | -8 500 kr | |

The results displayed in Table 30 and in Table 31 indicate that policy actions might have a significant impact on investment decisions in new generating capacity. This is interesting as the target group of electricity generation cost assessments often are stated as policy- and decision makers.

## 5.2 Impact of heat price

The income from heat sales is very important for CHP plants. It is however difficult to estimate the assumption on heat price. The assumption in section 5.1 is that the heat price is equivalent to the heat credit (239 SEK/MWh$_h$) used in the sensitivity analysis. The real price could however be significantly larger than this. The average price paid by costumers living in apartment buildings (not including VAT) in Sweden 2011 was 591 SEK/MWh$_h$ (Svensk Fjärrvärme, 2011). This price figure does however also contain the district heating network costs, and it might therefore not be directly applicable to use as a heat price assumption (if it should be internalised to the power plant). The heat price is also a local factor (the highest price in Sweden is more than twice as high as the lowest price) and also dependent on type of costumer (Energimarknadsinspektionen, 2012). A general heat price figure will therefore be impossible to state. A test on the economic indicators by increasing the base heat price assumption by 50% and by 100% is shown in Table 32. It clearly shows that the assumption on heat price is important as the economic indicators improve significantly for all power generating technologies when assuming higher heat prices.

**Table 32.** Impact of heat price on CHP indicators.

| Technology | Heat credit [SEK/MWhh] | | |
|---|---|---|---|
| | 232 | 348 | 464 |
| | | payback period [years] | |
| CHP-CCGT | 10.6 | 7.0 | 5.2 |
| CHP-B | 18.5 | 9.2 | 6.1 |
| CHP-W | 7.5 | 5.7 | 4.6 |
| | | Discounted payback period [years] | |
| CHP-CCGT | - | 15.0 | 9.0 |
| CHP-B | - | - | 11.5 |
| CHP-W | 19 | 10 | 7.5 |
| | | Net present value [SEK/kWe] | |
| CHP-CCGT | -2600 | 2 100 kr | 6 700 kr |
| CHP-B | -17200 | -3 300 kr | 10 700 kr |
| CHP-W | 9000 | 41 400 kr | 73 800 kr |

## 5.3 Results using increasing prices

This section shows how the results change by assuming an increasing electricity price, heat price, fuel price, and carbon emission cost. Assuming increasing prices can definitely be justified. Figure 43 shows how the Swedish Nord Pool Spot price developed from year 2000 to year 2010. Predicting future prices are however extremely difficult and the results presented here are based on simple assumptions. The objective is only to show the impact of price changes on the power plants economic viability. Two assumptions will be used; a moderate real price increase of 2% per year (for all categories) and a more bold assumption of a real price increase of 4% per year.

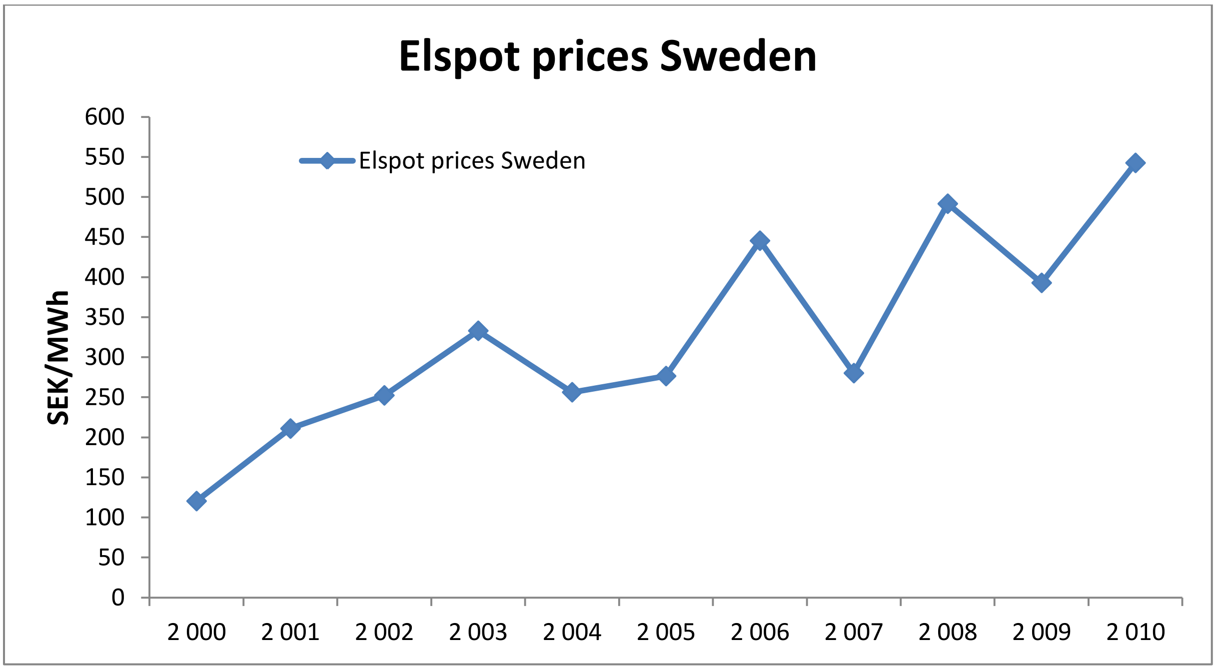


**Figure 43.** Elspot prices Sweden (Nord Pool Spot, 2012).

The simple payback period cannot be directly calculated when assuming increasing prices as the annual cash flows will differ from year to year. The simple payback period will instead be found by using the same approach as for the discounted payback period visualised in Figure 41.

Table 33 and Table 34 shows the economic indicators at 5% DR, and by assuming yearly real price increases of 2% and 4%. The economic indicators improve for all power plants, meaning that the increase in electricity price (and for CHP plants the increase in heat price) exceeds the cost increases.

**Table 33.** Economic indicators at a 2% yearly price increase (5% DR). "Long" stated for PV means that the payback time is significantly longer than the installation's assumed lifetime.

| Technology | Payback period [years] | Discounted payback period [years] | NPV [SEK/kWe] |
|---|---|---|---|
| Hard coal | 7.0 | 9.0 | 19 800 kr |
| CCGT-C | 13.5 | 23.0 | 500 kr |
| CCGT-CHP | 10.0 | 14.0 | 5 600 kr |
| Nuclear | 8.0 | 12.5 | 40 800 kr |
| CHP-B | 16.0 | - | -3 300 kr |
| CHP-W | 7.0 | 9.5 | 100 100 kr |
| Hp | 8.5 | 11.5 | 29 900 kr |
| Pv | long | - | -2 600 kr |
| Wp on | 10.0 | 14.5 | 4 600 kr |
| Wp off | 18.0 | - | -9 500 kr |

**Table 34.** Economic indicators at a 4% yearly price increase (5% DR). "Long" stated for PV means that the payback time is significantly longer than the installation's assumed lifetime.

| Technology | Payback period [years] | Discounted payback period [years] | NPV [SEK/kWe] |
|---|---|---|---|
| Hard coal | 6.5 | 8.0 | 28 300 kr |
| CCGT-C | 12.5 | 18.5 | 2 500 kr |
| CCGT-CHP | 9.0 | 12.0 | 9 500 kr |
| Nuclear | 7.5 | 11.5 | 69 800 kr |
| CHP-B | 14.0 | 22.5 | 2 600 kr |
| CHP-W | 6.5 | 8.5 | 144 200 kr |
| Hp | 8.0 | 10.5 | 50 000 kr |
| Pv | long | - | -2 600 kr |
| Wp on | 9.5 | 13.0 | 8 500 kr |
| Wp off | 16.0 | - | -6 100 kr |

The economic indicators at 10% DR, and at an assumed yearly real price increase of 2%, respectively 4%, are presented in Table 35 and in Table 36. The effect here is even more pronounced than in the 5% discount rate case. The effect on the indicators is quite significant and the changes are in some cases large enough to change the perception on an investment decision.

**Table 35.** Economic indicators at a 2% yearly price increase (10% DR).

| Technology | Payback period [years] | Discounted payback period [years] | NPV [SEK/kWe] |
|---|---|---|---|
| Hard coal | 7.0 | 14 | 5 500 kr |
| CCGT-C | 13.5 | - | -3 200 kr |
| CCGT-CHP | 10.0 | - | -1 100 kr |
| Nuclear | 8.0 | 36.5 | 800 kr |
| CHP-B | 16.0 | - | -14 900 kr |
| CHP-W | 7.0 | 14.5 | 26 200 kr |
| Hp | 8.5 | 23.5 | 3 700 kr |
| Pv | long | - | -2 800 kr |
| Wp on | 10.0 | - | -2 900 kr |
| Wp off | 18.0 | - | -17 800 kr |

**Table 36**. Economic indicators at a 4% yearly price increase (10% DR).

| Technology | Payback period [years] | Discounted payback period [years] | NPV [SEK/kWe] |
|---|---|---|---|
| Hard coal | 6.5 | 11.5 | 9 800 kr |
| CCGT-C | 12.5 | - | -2 200 kr |
| CCGT-CHP | 9.0 | 22.0 | 800 kr |
| Nuclear | 7.5 | 21.5 | 11 000 kr |
| CHP-B | 14.0 | - | -11 900 kr |
| CHP-W | 6.5 | 12.5 | 48 400 kr |
| Hp | 8.0 | 17.5 | 10 800 kr |
| Pv | long | - | -2 800 kr |
| Wp on | 9.5 | - | -700 kr |
| Wp off | 16.0 | - | -15 800 kr |

Wrangensten (2012) state that it might be difficult to take investment decisions in the future. This is a problem common to all technologies. A good forecast of coming electricity prices is highly needed, but this is not an easy task. Investment decisions will be difficult as future electricity prices are highly uncertain. This section has showed that an inaccurate assumption on future electricity prices is sufficient enough to change the opinion regarding investments in new generating capacity.

## 5.4 Using peak prices

Different power generating technologies have different production profiles. Baseload technologies (such as nuclear, coal and CCGT) produce electrical energy at a constant rate while peaking power plants (such as hydropower and gas turbines) can change their output rapidly in order to follow the variation in demand. Intermittent power sources are dependent on weather conditions and only produce electricity when those conditions are favourable. This would not be a problem if electricity would be sold at a constant price. However, as Figure 44 and Figure 45 shows, prices vary significantly from hour to hour, from day to day as well as over seasons. Baseload technologies will most likely be able to deliver electricity during those hours when the electricity price reaches high values due to their long operating periods. Peaking power plants are very likely to do so as this is their main purpose. There is, however, no guarantee that intermittent technologies will be able to deliver electricity during high price hours. They can do so, but this is not a given fact since this mostly depends on the weather conditions. The impact of this circumstance will be visualised in this section.


**Figure 44.** Nord pool hourly spot prices 24/5 2012 (Nord Pool Spot, 2012).

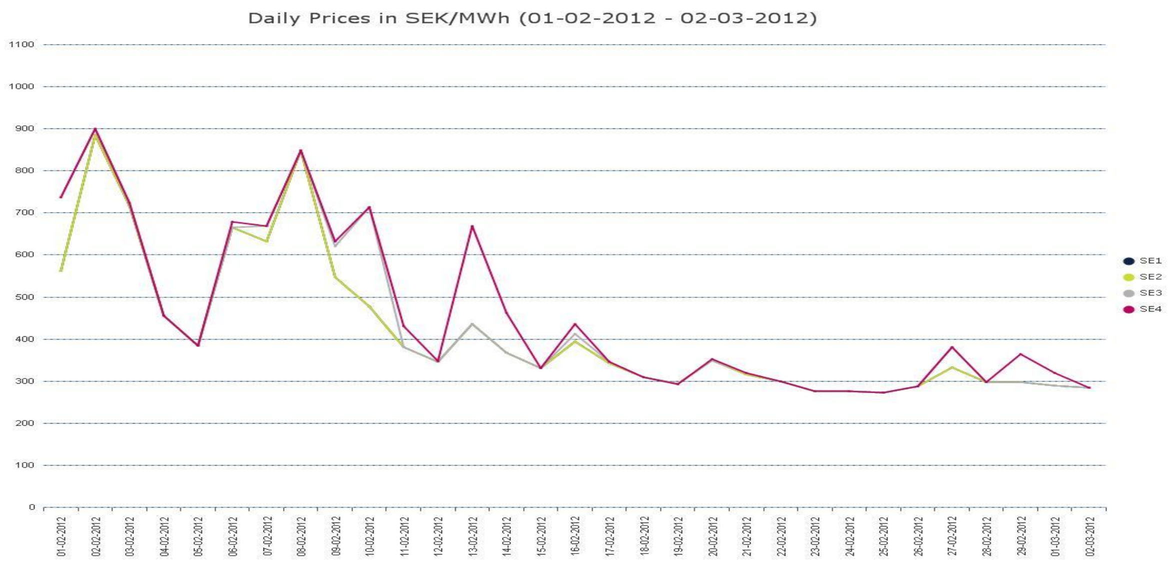


**Figure 45.** Nord pool daily spot prices February 2012 (Nord Pool Spot, 2012).

The assumed electricity prices and the assumptions on base- and peak hours have been presented in section 5 (Table 27). Table 37 shows how the economic indicators change for some power generating technologies when assuming different price periods (baseload, intermediate load and peak load). Observe that the assumption on capacity factor is constant. The only change is the assumption on when the electrical energy is delivered.

**Table 37.** Economic indicators electricity market value test [5% DR].

| Parameters | Price [SEK/MWh] | Hydropower | CCGT | WP onshore |
|---|---|---|---|---|
| Case 1 | | | | |
| Peak hours | 1006 | 464 | 786 | 383 |
| Intermediate hours | 684 | 618 | 1048 | 511 |
| Base hours | 442 | 2948 | 4998 | 2435 |
| Total hours | - | 4030 | 6833 | 3329 |
| PP [years] | | 8.9 | 15.3 | 11.2 |
| DPB [years] | | 13.5 | - | 17.5 |
| NPV [SEK(kWe] | | 17 100 kr | -1 000 kr | 1 500 kr |
| Case 2 | | | | |
| Peak hours | 1006 | 1008 | 1008 | 0 |
| Intermediate hours | 684 | 1344 | 1344 | 511 |
| Base hours | 442 | 1678 | 4481 | 2818 |
| Total hours | - | 4030 | 6833 | 3329 |
| PP [years] | | 7.2 | 10.7 | 13.3 |
| DPB [years] | | 10.0 | 16.5 | - |
| NPV [SEK(kWe] | | 18 000 kr | 2 000 kr | -1 400 kr |
| Case 3 | | | | |
| Peak hours | 1006 | 1008 | 1008 | 0 |
| Intermediate hours | 684 | 1344 | 1344 | 0 |
| Base hours | 442 | 1678 | 0 | 3329 |
| Total hours | - | 4030 | 2352 | 3329 |
| PP [years] | | 7.2 | 8.6 | 14.9 |
| DPB [years] | | 10.0 | 12.0 | - |
| NPV [SEK(kWe] | | 18 000 kr | 4 300 kr | -3 000 kr |

Case 1 corresponds to a situation where all electricity sells at the same price (Table 28). Case 2 shows how the situation changes if we assume that the wind power plant only is able to produce electricity during the baseload and intermediate load hours, and by assuming that the hydropower plant and the CCGT installation are able to follow peak load and intermediate load prices. Case 3 shows how the situation changes if we assume that the wind power plant only is able to produce electricity during the baseload hours. The hydropower station and the CCGT plant are favoured by the new situation while the wind power plant is negatively affected.

The CCGT plant tested in Table 37 is losing money in baseload operation. As this power plant is dispatchable it is not likely that it would operate under such conditions. By assuming that the CCGT plant only operates during peak load and intermediate load hours (another assumption on capacity factor) the economic indicators improve even more. This is visualised in case 3 (Table 37) for the CCGT plant. Why the LCOE methodology is an unsuitable measure for comparing dispatchable and intermittent power generating technologies is visualised by another example. Table 38 shows the levelised cost of a hypothetical nuclear power plant and a hypothetical wind power turbine. Given the input parameters presented in Table 38, these power plants have the same levelised cost of electricity. They might, however, exhibit different economic profitability, which is visualised in Table 39.

**Table 38.** Nuclear- and wind power plant with the same LCOE.

| Input parameter | Nuclear | Wind power |
|---|---|---|
| Net el power [MW] | 1600 | 3 |
| Capacity factor | 0,85 | 0,35 |
| Lifetime [years] | 40 | 25 |
| Discount rate [%] | 7.5 | 7.5 |
| Overnight cost [SEK/kWe] | 31000 | 14000 |
| Operating cost [SEK/MWhe] | 140 | 115 |
| Construction period [years] | 6 | 2 |
| Interest during construction [%] | 7,5 | |
| Cost outlays during construction | linear | |
| LCOE [SEK/MWhe] | 539 | 540 |

**Table 39.** Nuclear- and wind power economic indicators comparison.

| Parameters | Price [SEK/MWh] | Nuclear power | Wind power |
|---|---|---|---|
| Case 1 | | | |
| Peak hours | 1006 | 857 | 353 |
| Intermediate hours | 684 | 1142 | 470 |
| Base hours | 442 | 5447 | 2243 |
| Total hours | - | 7446 | 3066 |
| Payback period [years] | - | 10.3 | 10.6 |
| NPV [SEK/kWe] | - | 490 kr | 146 kr |
| Case 2 | | | |
| Peak hours | 1006 | 857 | 0 |
| Intermediate hours | 684 | 1142 | 470 |
| Base hours | 442 | 5447 | 2596 |
| Total hours | - | 7446 | 3066 |
| Payback period [years] | - | 10.3 | 12.5 |
| NPV [SEK/kWe] | - | 490 kr | -2 238 kr |
| Case 3 | | | |
| Peak hours | 1006 | 1008 | 0 |
| Intermediate hours | 684 | 1344 | 0 |
| Base hours | 442 | 5094 | 3066 |
| Total hours | - | 7446 | 3066 |
| Payback period [years] | - | 9.9 | 14.0 |
| NPV [SEK/kWe] | - | 2 304 kr | -3 600 kr |

The point with these examples were to show that even though power plants might exhibit similar LCOE figures, the economic value of the electricity they produce might differ between different technologies, making LCOE (as it is today) a bad measure for comparing dispatchable and non-dispatchable power generating technologies. Observe that the peak- and base prices used in these simple examples are based on weakly average values. The actual electricity price difference is larger when looking at hourly values, indicating that the differences in economic viability might be bigger than what is suggested by the examples in this section.

The failure of not accounting for different production profiles is also a market problem. The Nordic electricity market is an electric energy market, meaning that producers only get paid for the electrical energy that they produce. A possible solution is a capacity market where producers also are compensated for keeping the power plants in standby (Elforsk, 2011a). This would improve the economic profitability of dispatchable power plants such as coal power, CCGT, OCGT and hydropower. Note also that the economic evaluations provided in this chapter does not account for incomes related to selling regulating power.

# 6 Shortcomings- and improvement suggestions of existing methodologies

## 6.1 Deficiencies in existing methodologies

The presented shortcomings are important to keep in mind when looking at electricity generation cost assessments and when using the results.

- No inclusion of electricity system costs

Something that the reader should be aware of is that electricity system costs are not accounted for in any major extent. The electricity generation costs tend to be plant-level, meaning that external costs due to different grid effects, like transmission costs and other network costs such as impacts on system balancing and the need of reserve power, are not accounted for. These costs are however not negligible. For example, IEA and NEA (2010) states that transmission, distribution and marketing costs could account for up to 40% of the total electricity cost as a rule of thumb. Mott McDonald (2010) agrees and state that a full LCOE should include network costs such as transmission- and distribution costs, supply administration and network losses. These costs are stated to be in the same order of magnitude as the generation cost (with the system boundary at the power plant). As stated earlier, none of the reviewed studies account for these costs quantitatively. A widening of the system border would definitely raise the electricity generation cost, but it might also lead to different rankings of power generating technologies. If electricity generation cost assessments are to be used in planning and policy activities, network costs should be accounted for as different power plants have different impact on the electricity system. This topic will be more discussed further on.

- The LCOE methodology is not suitable for comparing intermittent- and dispatchable power generating technologies

Using the LCOE methodology to rank intermittent (weather dependent) and dispatchable power generation technologies should be done with caution. The reason is that the LCOE methodology fails to account for differences in production profiles and in the associated market value of electricity supplied by different power sources. The wholesale electricity price varies from hour to hour because of the variation in electricity supply and demand. It is more likely that a dispatchable power source will be able to produce electricity during those hours of the year when the electricity price soar compared to an intermittent alternative. This means that a dispatchable and an intermittent power generating technology may have the same levelised cost per e.g. $MWh_e$ produced, even though they can display very different net economic values and profitability (Joskow, 2011). This fact was visualised in chapter 5.

Joskow (2011) is critical of the LCOE metric and argues that it nowadays exist power system models capable of forecasting prices and time-warying demand. These models can also account for different network constraints and reliability issues. It is therefore fully possible to evaluate a power generating technology by looking at its expected market value of supplied electricity, its (life-cycle) costs, and the associated expected profitability. Joskow (2011) further means that this is exactly what a normal investor would do when considering investments in new power generating capacity.

The failure of not accounting for differences in production profiles is a shortcoming of current electricity generation cost methodologies. They do not differentiate between power and energy in an adequate way.

- No credits for providing  stable electricity generation costs

Power plants that are more likely to face stable generation costs during their lifetime, and therefore are able to retain the electricity price, are not attributed for this positive effect. The sensitivity analysis performed in chapter 4 showed that power generating technologies using fossil fuels to generate electricity are sensitive to fuel price changes/increases. These technologies are also struggling with big uncertainties in future prices on carbon emission costs. CHP-B- and CHP-W power plants are also sensitive to changes in fuel price.

Power generating technologies that generate electrical energy without using fuels are however “immune” to fuel price changes, if ignoring general price increases due to higher fossil fuel prices, and are not subject to carbon emission costs. This is also approximately true for nuclear power plants as fuel price increases needs to be considerable in order to have a large impact on the generation cost. The LCOE methodology does however fail to account for this important aspect.

Something related to the statements above are the power plants impact on system/state energy security. Building fuel independent power generating technologies might be a way for a country to reduce its dependence on foreign fuels, thereby improving the country’s energy security. Companies might also be interested in capacity investments due to concerns regarding future electricity prices. This is another aspect not captured by the LCOE methodology.

- External costs are often missing

External costs due to power plants impact on e.g. human health, wildlife and climate change are recognized by some of the reviewed studies (CASES, 2008a, EUSUSTEL, 2007e, NEEDS, 2009a). These costs are calculated with life cycle assessment - LCA approaches. The reported external cost figures for fossil-fired power plants, PV and biomass-fired technologies are quite significant, leading to substantially higher electricity generation costs for these technologies.

Internalising the costs due to external effects is however not an easy task. LCA results are shown to be dependent on methodology approaches and on underlying assumptions (Davidsson et al., 2012). Nevertheless, external cost assessments provide valuable information about power plants impact on their environment, something that the LCOE methodology fails to do.

## 6.2 Suggestions for improvements of existing methodologies

### 6.2.1 The need for transparency

Transparency is here interpreted as openness of decisions, actions and information. This is needed in order to evaluate the credibility of performed studies. In electricity generation cost assessments, transparency is also needed so that the readers are able to properly follow and understand the actions that are taken in the electricity generation cost calculations.

The problem is that all of the reviewed studies have more or less transparency issues. The data sources are in most cases hidden and unavailable to the reader. In some cases the models are unavailable and too complex to understand. Assumptions and sources are not always motivated and methodologies are sometimes poorly explained. Reports are sometimes hard to interpret as results are missing or in conflict with figures stated elsewhere. The reports might also be time-consuming and difficult to read as their contents are poorly explained and information is difficult to locate.

These issues makes it complicated, and in some cases virtually impossible, to understand how the studies arrive at their results, but it also raise questions about the reliability and usefulness of the presented figures.

However, these issues could be avoided if studies were to put more attention on transparency in their reports. The methodology approach should be clearly explained and the model or the used formula/formulas should be provided to the reader. The model/formulas should also be explained and exemplified so that the reader understands how the model works and also how to use it.

All necessary information should be available in easy-to-read reports in order to avoid misconceptions and misinterpretations. The information should be public and traceable back to its original source. This prevents reliability issues from occurring.

### 6.2.2 Input data

The input data sources should be provided to the reader. If this is not possible, for instance due to confidentiality reasons, a general description of the different sources should be provided. It should be stated whether the report focus on generation costs for e.g. “best available technologies”, specific projects, or on something else. It is also important that it is stated whether the reported cost figures are based on data from e.g. existing (already built) power plants, projects under construction, planned projects, literature sources, or on data provided by manufacturers.

The number of data points, in this case the number of power plants, used when estimating different cost figures should also be stated. It is interesting to know whether cost data are based on a single project or on multiple installations of the same technology. In this way a better understanding of the site-specific characteristics of the power plant in question is provided.

### 6.2.3 Presentation of results

The generation cost figure should be presented together with the uncertainties in the assessment. For example, a "best guess" estimate could be presented together with an interval showing the spread due to different uncertainties. Stating general generation cost figures is acceptable if such numbers are explicitly asked for and if the shortcomings with such an approach are explained. It is however questionable if such an approach should be used in a public context as a reference to the electricity generation cost of a specific power generating technology.

The presented cost figures must also be complemented by a detailed sensitivity analysis. Such an analysis is needed in order to make the reader aware of the uncertainties in the assessments and of the sensitivity to changes in crucial parameters.

### 6.2.4 Avoid mixing of different technologies

Aggregating cost figures for a "general" technology category such as "photovoltaics" or "nuclear power" is not recommended. It is clearly a large difference between e.g. different types of nuclear reactors and different types of photovoltaic technologies. It is therefore dubious that some studies aggregate such different technologies into a common figure. This is not recommended. It should be clearly stated which kind of specific technology the cost figures are based on. By doing this, the reader can as far as possible avoid the problem with comparing apples and oranges.

### 6.2.5 Widen the system border and account for differences in production profiles

Levelised cost of electricity has become the most popular metric for comparing different power generating technologies. The methodology focus on costs for the producers, but what about other costs that are met by the consumers? Current electricity generation cost methodologies does not account for power plants different impact on the electricity system as a whole. Ekholm (2012) state that the reason might be that in system analysis it is difficult to assign a cost to a specific technology as the price of electricity is the sum of all parts in the system. The system effects might however often be important.

Hirschberg (2012) state that system costs are essential and that they depend on the structure of the electricity system in question. The biggest relative difference between various technologies should however be on the level of generation costs. The other factors are difficult to impute to a single technology. A lot of stochastic resources will lead to significantly higher backup costs and grid requirements. The figures will depend on the electricity system under consideration and on the analysed scenario. As long as intermittent sources constitute a small part of the electricity system they do not matter in terms of system costs. However, if intermittent sources start to make up over 5% of installed capacity, then backup costs will obviously count.

Henryson's (2012) opinion is that the system perspective in general is absent and that the reason is lack of data and actors taking a holistic approach. Transmission and regulating capacity would probably be the most specific aspects, but a wider perspective would also include environmental effects, risk of accidents, employment opportunities, etc. Henryson (2012) also state that discussions regarding improved energy efficiency is missing in the debate, even though it might be the most cost-effective alternative.

Widening the system border would most likely imply higher generation cost for all power generating technologies. The cost increases would however be more substantial for the intermittent power sources (IEA and NEA, 2010, MIT Energy Initiative, 2011). A methodology that calculates costs per produced unit of energy might simply not be the best methodology to account for costs that arise from energy that is not produced.

IEA & NEA (2010) state three different cost categories for system integration of intermittent sources. 1) balancing scheduled and unscheduled change in output, 2) investments in needed flexible capacity, and 3) transmission investments. There is however little agreement of how substantial the extra system and network costs could be. IEA & NEA (2010) has compiled a number of different integration studies showing cost increases due to the additional use of existing flexible power sources to balance wind power in the range of 7-41 SEK/MWh$_e$. The cost increases with higher shares of wind power in the system.

CIViTAS (Williams, 2012) claims additional costs for  integration of wind power into the British electricity system of at least 208 SEK/MWh$_e$ by 2020. Mills et al. (2011) have summarised wind power transmission costs from 40 different U.S. transmission studies. The range is huge with an investment cost between 0-9750 SEK/kW$_e$ of installed wind capacity. The median value is 1950 SEK/kW$_e$. This corresponds to a busbar transmission cost of 0-514 SEK/MWh$_e$, with a median value of 98 SEK/MWh$_e$. These transmission costs are for U.S. conditions, but they are interestingly to notice as there are considerable amounts of wind power planned to being installed in the northern parts of Sweden at the moment.

This study has not looked at the methodologies used in these integration cost studies or investigated if they are relevant for Swedish/Nordic conditions. However, there is no doubt that integration cost exists and that they may very well be significant. Integration costs of intermittent power sources should not be considered as way of discriminating these technologies. Instead, they should be considered as a technical reality in need of more consideration.

Something related to missing system costs is the problem that current electricity generation cost assessments fail to account for differences in production profiles between intermittent and dispatchable power sources. Current methodologies take no account for differences in power "quality" of various generating technologies. Power and energy is treated in the same manner. One way to handle these differences is to incorporate the variations in the market value of the electricity that they supply.

Accounting for system costs and different production profiles is relevant if the studies aim at providing policy- and decision makers with generation cost figures. If the results are to be used in decision making, when forming policies, or when making prognoses, it is relevant that the methodology captures all of the costs borne by a certain power generating technology. This is needed in order to properly evaluate the costs (and benefits) of subsidies to renewable technologies and, as the introduction of renewables often is seen as a way of combating climate change, to calculate the cost of reducing carbon dioxide emissions. This is important as there might be other, more cost efficient ways of reducing carbon dioxide emissions (such as aiding energy efficiency programs, promoting nuclear power, or combating carbon dioxide emissions in the transport area). A methodology that captures all system costs, and benefits, would therefore be superior to current alternative as avoided costs, benefits, and reductions in carbon dioxide emissions could be compared to other alternatives pointing in the same direction.

# 7 Discussion

## 7.1 Regional issues

Something worth discussing is if it is meaningful to compare electricity generation cost assessments conducted in different regions or countries to each other. Are costs country-specific or can they be generalised?

IEA & NEA (2010) collect cost figures (such as investment- and O&M costs) from a range of different countries, both within and outside the EU. These cost figures are then used to calculate the LCOE for each power plant included in the study. Figure 46 shows large differences in the calculated LCOE between different regions (such as Asia compared to Europe), but it also shows that there are substantial differences within the same regions. A key conclusion drawn by IEA & NEA (2010) is that country-specific circumstances have a major impact on the LCOE.

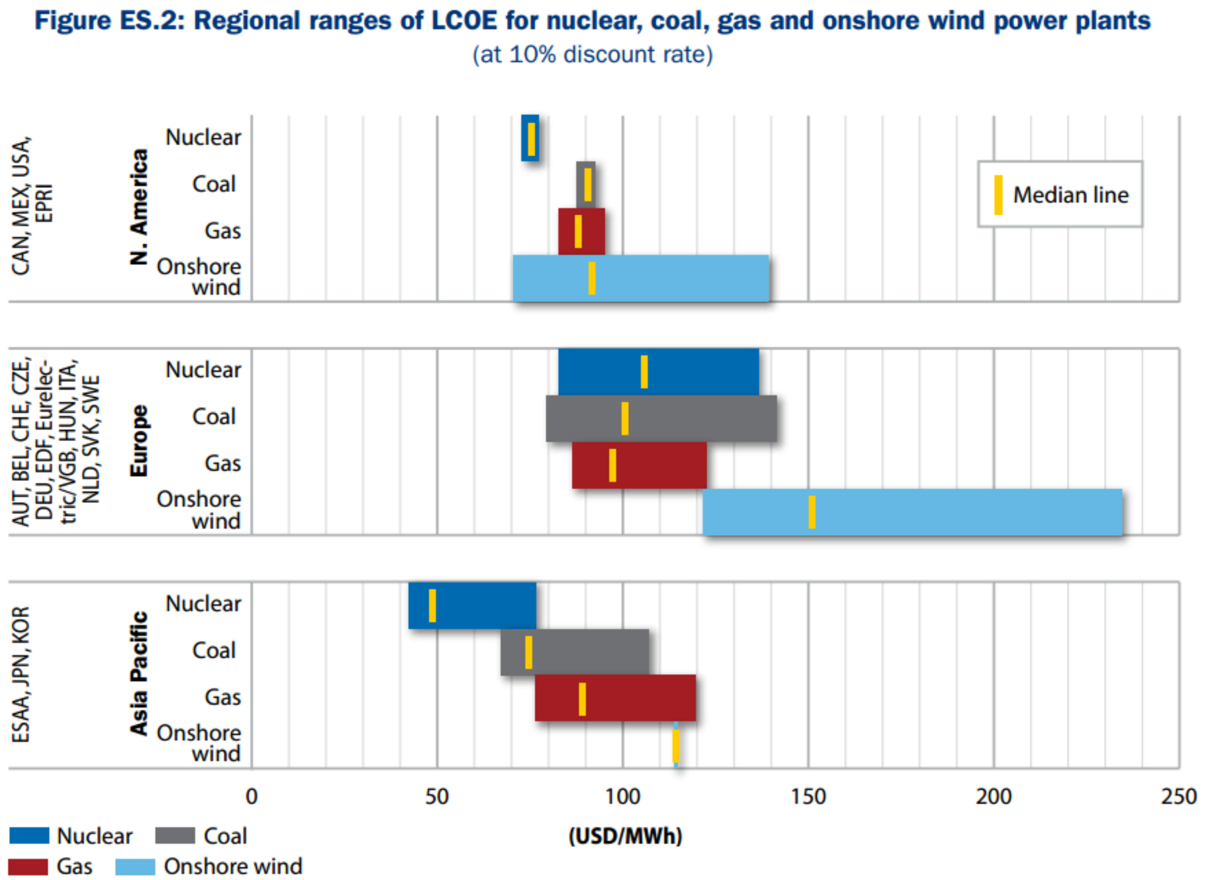


**Figure 46.** Regional LCOE differences (IEA and NEA, 2010).

Figure 46 shows that different power generating technologies cost ranges overlap each other. This makes it hard to state that the generation cost of one technology would be lower than that of another. It is also an indicator on that it is not possible to trust a price figure from a single cost analysis. Ekholm (2012) has an interesting point in that it might be possible to use probabilistic approaches in order to state how likely it is that one technology is less costly than another.

The underlying differences between the reviewed studies are impossible to know as the costs are lumped together and presented as single figures (the component issue). All indicators do however point to the fact that country-specific differences have a large impact on the generation cost results. This circumstance highlights the need to look at electricity generation costs at country level.

## 7.2 Economies of scale

Economies of scale seem to be an important factor when it comes to electricity generation costs. Mott McDonald (2010) state that there are significant economies of scale in electricity generation, especially when considering steam turbine plants. IEA & NEA (2010) state that economies of scale is an important factor for coal, nuclear and hydropower plants. The Elforsk (2011b) model clearly shows that economies of scale is an important factor for CHP-CCGT and CHP-B as larger units have higher electrical efficiency, lower specific investment costs and lower O&M costs. The opposite trend for wind power in the Elforsk (2011b) study can partly be explained by increasing investment costs due to assumptions on higher towers and larger foundations for bigger wind power turbines. Some examples of economies of scale in the reviewed studies are given in Table 40.

**Table 40.** Examples of economies of scale.

| Study | Technology | Generation cost (SEK/MWh$_e$) | Difference (%) |
|---|---|---|---|
| Elforsk | CHP-B, 80 MW | 978 | 27 |
| | CHP-B, 30 MW | 1243 | |
| | CCGT-CHP, 150 MW | 630 | 45 |
| | CCGT-CHP, 40 MW | 914 | |
| | Wp on, 20*3 MW | 785 | -4 |
| | Wp on, 1*1 MW | 755 | |
| | Wp off, 75*5 MW | 1302 | -9 |
| | Wp off, 50*3 MW | 1181 | |
| CASES | ROR, 50 MW | 1225 | 16 |
| | ROR, 1 MW | 1424 | |
| EUSUSTEL | Wp on, 2 MW | 640 | -25 |
| | Wp on, 0,75 MW | 482 | |
| | PV, 0,0001 MW | 4065 | 21 |
| | PV, 0,00005 MW | 4921 | |

It is easy to see that economies of scale might have a significant impact on the generation cost result. This finding entails two things:

1. Stating a general generation cost figure for a given power generating technology will be difficult.
2. There is a risk of comparing apples and oranges when looking at different electricity generation cost assessments.

## 7.3 The impact of time

A relevant question is for how long results from electricity generation cost assessments could be used. Chapter 3.1.3 showed that investment costs can change rapidly over time. It therefore seems as if electricity generation cost studies have a fairly short expiration date. Figure 47 shows investment cost differences between the AEO2011 and the AEO2010 studies. There are significant differences even though the studies are separated by only one year in time.

Table 2. Comparison of Updated Plant Costs to *AEO2010* Plant Costs

| Table II | | | | | |
|---|---|---|---|---|---|
| | Overnight Capital Cost ($/kW) | | | Nominal Capacity KWs[1] | |
| | AEO 2011 | AEO 2010 | % Change | AEO 2011 | AEO 2010 |
| **Coal** | | | | | |
| Advanced PC w/o CCS | $2,844 | $2,271 | 25% | 1,300,000 | 600,000 |
| IGCC w/o CCS | $3,221 | $2,624 | 23% | 1,200,000 | 550,000 |
| IGCC CCS | $5,348 | $3,857 | 39% | 600,000 | 380,000 |
| **Natural Gas** | | | | | |
| Conventional NGCC | $978 | $1,005 | -3% | 540,000 | 250,000 |
| Advanced NGCC | $1,003 | $989 | 1% | 400,000 | 400,000 |
| Advanced NGCC with CCS | $2,060 | $1,973 | 4% | 340,000 | 400,000 |
| Conventional CT | $974 | $700 | 39% | 85,000 | 160,000 |
| Advanced CT | $665 | $662 | 0% | 210,000 | 230,000 |
| Fuel Cells | $6,835 | $5,595 | 22% | 10,000 | 10,000 |
| **Nuclear** | | | | | |
| Nuclear | $5,339 | $3,902 | 37% | 2,236,000 | 1,350,000 |
| **Renewables** | | | | | |
| Biomass | $3,860 | $3,931 | -2% | 50,000 | 80,000 |
| Geothermal | $4,141 | $1,786 | 132% | 50,000 | 50,000 |
| MSW - Landfill Gas | $8,232 | $2,655 | 210% | 50,000 | 30,000 |
| Conventional Hydropower | $3,078 | $2,340 | 32% | 500,000 | 500,000 |
| Wind | $2,438 | $2,007 | 21% | 100,000 | 50,000 |
| Wind Offshore | $5,975 | $4,021 | 49% | 400,000 | 100,000 |
| Solar Thermal | $4,692 | $5,242 | -10% | 100,000 | 100,000 |
| Photovoltaic | $4,755 | $6,303 | -25% | 150,000 | 5,000 |

[1] Higher plant capacity reflects the assumption that plants would install multiple units per site and that savings could be gained by eliminating redundancies and combining services.

**Figure 47.** Change in the Annual Energy Outlook investment cost assumptions (EIA, 2010b).

Some other examples of the impact of time on electricity generation costs are provided in Table 41. In the Elforsk (2007, 2011b) case significant cost increases (for some power generating technologies) can be observed over a time period of four years, while in the DECC case (PB, 2011, Arup, 2011, Mott MacDonald, 2010) significant cost decreases have occurred during a very short time period.

**Table 41.** Examples of the impact of time on electricity generation costs.

| Elforsk 2007 | Generation cost (6% DR) | Elforsk 2011 | Generation cost (6% DR) | Difference (%) |
|---|---|---|---|---|
| CHP-B, 80 MW | 730 | CHP-B, 80 MW | 742 | 2 |
| CHP-B, 30 MW | 918 | CHP-B, 30 MW | 948 | 3 |
| CCGT-CHP, 150 MW | 412 | CCGT-CHP, 150 MW | 546 | 33 |
| CCGT-CHP, 40 MW | 481 | CCGT-CHP, 40 MW | 803 | 67 |
| WP off, 150 MW | 801 | WP off, 150 MW | 896 | 12 |
| Nuclear, 1600 MW | 295 | Nuclear, 1600 MW | 453 | 54 |
| | | | | |
| **DECC 2010** | Generation cost (10% DR) | **DECC 2011** | Generation cost (10% DR) | Difference (%) |
| CCGT | 871 | CCGT | 813 | -7 |
| Coal ASC | 1117 | Coal ASC | 1013 | -9 |
| Nuclear | 1061 | Nuclear | 786 | -26 |
| Wp offshore | 1939 | Wp offshore | 1612 | -17 |

The differences presented in this section clearly points to a large impact of time on electricity generation cost assessments. Costs appear to change rapidly with time and being careful when looking at electricity generation cost assessments conducted in the past is therefore recommended. It is hard to state how significant the impact of time really is, but as described here, it might take as little as one year before a study is outdated.

## 7.4 Impact of system boundary

The electricity generation cost assessments reviewed in this study does not consider the technical aspects, and the related costs, with integrating power generating technologies into the electricity system.

Studies investigating electricity system integration costs seem rather rare, indicating that the area is in need of a lot of research and that relevant cost assumptions might be hard to find. If studies cannot account for system costs in a quantitative manner, at least they should be thoroughly discussed in a qualitative way. The impact of changing system boundary is not clearly communicated in the reviewed studies. More effort has to be put on explaining the limitations with placing the system boundary at the power plant terminals. References to electricity generation cost figures are commonly used in the public debate and it is bad if people interpret them as total electricity system costs.

## 7.5 Site-specific issues

The habit of presenting electricity generation costs as single figures is pronounced. This is often a bad idea as generation costs for some power generating technologies are site-specific. These technologies include hydropower, CHP plants and intermittent power sources. Hydropower because of site-specific capital costs, CHP due to site-specific heat credits and receiving fees, and intermittent sources due to the variation in capacity factor. Other power generating technologies also display site-specific costs tendencies. The impact is however more pronounced for hydropower, CHP, wind power and PV compared to the other alternatives. Stating certain generation cost figures can only be recommended when referring to specific projects at specific locations. Such generation cost figures can also be acceptable if they are explicitly asked for by a client. The limitations with such as approach should nevertheless be clearly communicated and the results should not be used in a public context.

## 7.6 Comparing apples and oranges

The risk of comparing apples and oranges has already been discussed in relation to economies of scale. The risk is however present even when looking at similar installation sizes. The reason is that different studies look at power plants with different technological characteristics.

It is difficult to assess how significant this impact might be. Generalising cost figures in a too large extent is however not a good idea. Technological differences might be significant even though the “base” technology is the same. Cost differences do not need to be correlated to different technological aspects, but it is a possibility and something that readers need to be aware of.

## 7.7 The impact of electricity generation cost assessments

The purpose of electricity generation cost assessments is often to provide policy- and decision makers with electricity generation cost figures of different power generating technologies. Such figures are also used in energy market analysis and projections. This means that impact of electricity generation cost assessments might be significant.

This study has showed that referring to electricity generation cost assessments in a public context should be done with caution. Generation costs are site-specific, sensitive to changes in input parameters and methodology dependent. Generalising electricity generation costs can therefore be questioned. On top of this, current methodologies are not suitable when comparing intermittent and dispatchable power generating technologies.

# 8 Conclusions

- Different methodological approaches and assumptions have a significant impact on the electricity generation cost results. Different studies are therefore not directly comparable with each other and results might differ substantially. Methodological differences should always be kept in mind when looking at electricity generation cost assessments.
- Generalising electricity generation costs is not recommended as costs tend to be site-specific and sensitive to changes in input parameters.
- Current electricity generation cost methodologies are not suitable for comparing intermittent power generating technologies with dispatchable power sources. The reasons are missing electricity system cost perspective and failure to account for differences in production profiles.
- Electricity generation costs are country specific. Country specific circumstances have a big impact on the electricity generation cost results, which highlight the need to look at electricity generation costs at country level.
- The impact of time is significant. Costs change rapidly with time and studies might therefore be outdated shortly after their publication.
- Lack of transparency is a problem and contributes to credibility issues. Input data sources, cost calculation models and used formulas are frequently not available to the readers and poorly explained. Costs are only presented as lumped figures which make them difficult to understand and compare.

# 9 Future work

This thesis has addressed the problems with system costs and differences in production profiles. It is however important to keep in mind that assumptions on external costs arising from power plants (the emissions) impact on human health, climate change and ecosystems can also be significant. These costs are usually calculated by using life cycle assessment (LCA) methodology. The basic steps are to calculate the lifecycle emissions, evaluate what physical impact these emissions have on the surroundings, and finally valuate these impacts in monetary terms. All of these steps involve different uncertainties and assumptions. Davidsson et al. (2012) have shown that several potential issues exist regarding the way LCA methods are used for assessing the environmental impact of wind energy. An excellent scope of future work would therefore be to review how different studies estimate external costs.

Many of the reviewed studies also focus on calculating future electricity generation costs. Such assessments are often based on different assumptions on learning curves and on technology improvements. Another suggestion of future work would therefore be to look into how different studies estimate future electricity generation costs.

In a bigger perspective, plenty of research is needed in assessing the economic impact of large-scale introduction of intermittent power sources onto the electricity system.

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# Appendix

## A Prepared questions for the panel debate at the RSAS

- What is the main purpose of electricity generation cost analyses? What are the pros and cons with these analyses?
- How big is the impact from using different methodologies? Do you think that methodological differences are a problem?
- Some parameters have a large impact on the electricity generation cost. However, in many cases a detailed sensitivity analysis is not included in the report. One might choose to display the results by using e.g. different discount rates or different investment cost. The impact of other major parameters is however ignored. Would you say that this is a problem? Is it reasonable to assume that the reader are aware of these circumstances and that one therefore can choose not to present sensitivity analysis results?
- Related to the sensitivity problem implied above, how “solid” and trustworthy are figures stemming from electricity generation cost analyses? Since some parameters have a major impact on the final result, would it therefore be a better idea to present electricity generation costs by using an interval showing the uncertainties in the assessments, instead of presenting a given figure (which implies a high level of certainty). Is it even relevant to talk about a certain electricity generation cost for a given technology?
- In many cases the input data sources are hidden and not available to the reader. Would you say that this is a problem? Can results still be trusted? Would you say that transparency is a problem in electricity generation cost analyses?
- For how many years can electricity cost analyses results be used? How long does it take before they are outdated?
- How large is the impact of regional differences (such as different tax systems, different costs for raw material and labour, etc)? Can one use results from cost analyses performed in particular regions/countries and implement them on another country?
- Different studies apparently arrive at different conclusions. Do you think that electricity generation costs results can have a too large impact in the society? Are people aware of the limits with these analyses? How careful should one be when referring to electricity generation cost assessments?
- Why are system costs (the impact of the power plant on the entire electricity system) rarely or never included in electricity generation cost assessments? Do you think that the generation cost would rise substantially for some (or all) power generating technologies if one would widen the system boundary so that the e.g. transmission, distribution and backup costs are included in the cost assessments?

# B Number of different cases for the included power generation technologies

**Table B1.** Number of different cases for each power generation technology. SKGS use three different investment cost figures for all selected technologies to account for a "low risk", a "high risk" and a "normal" case. For nuclear power they also present a separate case with a higher discount rate to reflect higher financial risk associated with a nuclear power plant project. EUSUSTEL and VGB use two different cases for coal condensing power plants, one for lignite coal power plants and one for hard coal power plants. Elforsk use 4 different plant sizes and CASES two different fuels (wood and straw) for CHP-B power plants. CASES and EUSUSTEL use three, respectively two different plant sizes for ROR hydro. EUSUSTEL also use two different plant sizes for reservoir hydro. VGB only account for ROR-hydro while the hydropower stations in the Elforsk and SKGS studies most likely are reservoir applications. EUSUSTEL use two different plant sizes for CCGT-C and CCGT-CHP. Elforsk and CASES also use the same approach for CCGT-CHP. CASES use two different PV options, open-space- and rooftop applications. EUSUSTEL use two different plant sizes for PV and nuclear power. Elforsk use three different cases for wind power, one for a single turbine application and two for different net wind farm sizes. EUSUSTEL and VGB use two different turbine sizes for onshore wind power. For wind power offshore, Elforsk use two different wind farm sizes, while EUSUSTEL and VGB present cost figures for two, respectively four different cases.

| Study | Power generating technology | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | CC | CHP-B | CHP-W | HP | CCGT-C | CCGT-CHP | OCGT | PV | NP | WP onshore | WP offshore |
| CASES | 1 | 2 | | 4 | 1 | 2 | 1 | 2 | 1 | 1 | 1 |
| Elforsk | 1 | 4 | 1 | 2 | 1 | 2 | | 1 | 1 | 3 | 2 |
| EUSUSTEL | 2 | | | 4 | 2 | 2 | | 2 | 2 | 2 | 2 |
| NEEDS | 2 | 2 | | | 1 | | 1 | 3 | 1 | | 1 |
| SKGS | | | | 3 | | | | | 6 | 3 | |
| DECC | 1 | 1 | 1 | 2 | 1 | 3 | 1 | 1 | 1 | 2 | 3 |
| EIA | 1 | | | 1 | 2 | | 2 | 1 | 1 | 1 | 1 |
| VGB | 2 | | | 1 | 1 | | 1 | | 1 | 2 | 4 |

**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** |

**Figure B1.** Total number of power plants included in the IEA & NEA (2010) study.

# C EIA discount rate projection

**Table C1.** EIA discount rate projection (Martin, 2012).

| Year | Debt share | Equity share | Tax rate |
|---|---|---|---|
| | 0,45 | 0,55 | 0,38 |
| | Cost of debt | Cost of equity | After tax WACC |
| 2008 | 0,074 | 0,112 | 0,082 |
| 2009 | 0,073 | 0,108 | 0,080 |
| 2010 | 0,059 | 0,106 | 0,075 |
| 2011 | 0,054 | 0,100 | 0,070 |
| 2012 | 0,062 | 0,114 | 0,080 |
| 2013 | 0,071 | 0,124 | 0,088 |
| 2014 | 0,078 | 0,128 | 0,092 |
| 2015 | 0,081 | 0,133 | 0,095 |
| 2016 | 0,081 | 0,133 | 0,096 |
| 2017 | 0,082 | 0,134 | 0,097 |
| 2018 | 0,082 | 0,134 | 0,097 |
| 2019 | 0,082 | 0,134 | 0,097 |
| 2020 | 0,082 | 0,134 | 0,096 |
| 2021 | 0,081 | 0,133 | 0,096 |
| 2022 | 0,081 | 0,133 | 0,096 |
| 2023 | 0,081 | 0,133 | 0,096 |
| 2024 | 0,081 | 0,133 | 0,096 |
| 2025 | 0,081 | 0,133 | 0,095 |
| 2026 | 0,081 | 0,133 | 0,095 |
| 2027 | 0,081 | 0,133 | 0,096 |
| 2028 | 0,081 | 0,133 | 0,096 |
| 2029 | 0,081 | 0,133 | 0,096 |
| 2030 | 0,081 | 0,133 | 0,095 |
| 2031 | 0,081 | 0,133 | 0,096 |
| 2032 | 0,082 | 0,133 | 0,096 |
| 2033 | 0,082 | 0,134 | 0,096 |
| 2034 | 0,083 | 0,134 | 0,096 |
| 2035 | 0,083 | 0,134 | 0,097 |
| average 2010-2035 | | | 0,093 |

# D Fuel prices

## D1 CASES

| Energy Carrier | Unit | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|---|
| Coal | [EUR/GJ] | 1.96 | 1.86 | 1.97 | 2.07 | 2.14 | 2.19 |
| Lignite | [EUR/GJ] | 0.97 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| Natural gas | [EUR/GJ] | 6.11 | 6.32 | 6.03 | 5.95 | 6.62 | 6.63 |
| Oil | [EUR/GJ] | 6.65 | 5.35 | 5.39 | 5.82 | 6.70 | 7.14 |
| Light Oil | [EUR/GJ] | 9.83 | 8.53 | 8.57 | 9.01 | 9.89 | 10.32 |
| Nuclear Repository | [EUR/GJ] | 0.62 | 0.62 | 0.62 | 0.62 | 0.62 | 0.62 |
| Biomass/Biogas[1)] | [EUR/GJ] | 4.00 | 4.00 | 4.00 | 4.00 | 4.00 | 4.00 |

[1)] Wood residual

**Figure D1.** Cases (2008a) fuel prices.

### D2 DECC

| Year | Low oil prices ($/bbl 2011 real) | Central oil prices ($/bbl 2011 real) | High oil prices ($/bbl 2011 real) |
|---|---|---|---|
| 2 010 | 82 | 82 | 82 |
| 2 011 | 110 | 110 | 110 |
| 2 012 | 107,8 | 111 | 112,5 |
| 2 013 | 105,7 | 112 | 115,2 |
| 2 014 | 103,5 | 112,9 | 117,8 |
| 2 015 | 101,5 | 113,9 | 120,6 |
| 2 016 | 99,5 | 114,9 | 123,4 |
| 2 017 | 97,5 | 116 | 126,2 |
| 2 018 | 95,5 | 117 | 129,1 |
| 2 019 | 93,6 | 118 | 132,1 |
| 2 020 | 91,7 | 119,1 | 135,2 |
| 2 021 | 89,9 | 120,1 | 138,3 |
| 2 022 | 88,1 | 121,2 | 141,5 |
| 2 023 | 86,4 | 122,2 | 144,8 |
| 2 024 | 84,6 | 123,3 | 148,2 |
| 2 025 | 83 | 124,4 | 151,6 |
| 2 026 | 81,3 | 125,5 | 155,1 |
| 2 027 | 79,7 | 126,6 | 158,7 |
| 2 028 | 78,1 | 127,7 | 162,4 |
| 2 029 | 76,5 | 128,9 | 166,1 |
| 2 030 | 75 | 130 | 170 |

| Year | Low gas prices (p/therm 2011 real) | Central gas prices (p/therm 2011 real) | High gas prices (p/therm 2011 real) |
|---|---|---|---|
| 2 010 | 44 | 44 | 44 |
| 2 011 | 63 | 63 | 63 |
| 2 012 | 48 | 69 | 79 |
| 2 013 | 32 | 74 | 81 |
| 2 014 | 33 | 80 | 83 |
| 2 015 | 33 | 81 | 85 |
| 2 016 | 33 | 81 | 87 |
| 2 017 | 34 | 76 | 89 |
| 2 018 | 34 | 70 | 91 |
| 2 019 | 35 | 70 | 93 |
| 2 020 | 36 | 70 | 95 |
| 2 021 | 37 | 70 | 97 |
| 2 022 | 38 | 70 | 100 |
| 2 023 | 39 | 70 | 100 |
| 2 024 | 40 | 70 | 100 |
| 2 025 | 41 | 70 | 100 |
| 2 026 | 42 | 70 | 100 |
| 2 027 | 43 | 70 | 100 |
| 2 028 | 44 | 70 | 100 |
| 2 029 | 44 | 70 | 100 |
| 2 030 | 45 | 70 | 100 |

**Figure D2A.** DECC oil and gas price projection (DECC, 2011a).

| Year | Low coal prices ($/tonne 2011 real) | Central coal prices ($/tonne 2011 real) | High coal prices ($/tonne 2011 real) |
|---|---|---|---|
| 2 010 | 93 | 93 | 93 |
| 2 011 | 130 | 130 | 130 |
| 2 012 | 124 | 130 | 137 |
| 2 013 | 117 | 127 | 143 |
| 2 014 | 112 | 124 | 144 |
| 2 015 | 106 | 121 | 146 |
| 2 016 | 101 | 119 | 147 |
| 2 017 | 96 | 116 | 148 |
| 2 018 | 91 | 113 | 149 |
| 2 019 | 85 | 110 | 151 |
| 2 020 | 80 | 110 | 152 |
| 2 021 | 80 | 110 | 153 |
| 2 022 | 80 | 110 | 153 |
| 2 023 | 80 | 110 | 154 |
| 2 024 | 80 | 110 | 154 |
| 2 025 | 80 | 110 | 155 |
| 2 026 | 80 | 110 | 155 |
| 2 027 | 80 | 110 | 155 |
| 2 028 | 80 | 110 | 155 |
| 2 029 | 80 | 110 | 155 |
| 2 030 | 80 | 110 | 155 |

**Figure D2B.** DECC coal price projection (DECC, 2011a).

## D3 EIA

**Energy Prices by Sector and Source, United States, Reference case**
**(2009 dollars per million Btu, unless otherwise noted)**

| Sector and Source | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Electric Power 9/** | | | | | | | | | | | |
| Distillate Fuel Oil | 19.56 | 14.33 | 16.38 | 17.22 | 15.72 | 16.07 | 16.46 | 16.84 | 17.62 | 18.29 | 18.88 |
| Residual Fuel Oil | 14.75 | 8.96 | 11.43 | 12.12 | 11.93 | 12.25 | 12.76 | 13.17 | 13.66 | 14.04 | 14.48 |
| Natural Gas | 9.10 | 4.82 | 5.07 | 4.72 | 4.65 | 4.64 | 4.60 | 4.67 | 4.71 | 4.75 | 4.80 |
| Steam Coal | 2.07 | 2.20 | 2.26 | 2.22 | 2.16 | 2.12 | 2.10 | 2.11 | 2.13 | 2.14 | 2.13 |

| Sector and Source | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Electric Power 9/** | | | | | | | | | | | | |
| Distillate Fuel Oil | 19.45 | 19.78 | 20.04 | 20.30 | 20.56 | 20.96 | 21.20 | 21.45 | 21.67 | 21.91 | 22.12 | 22.31 |
| Residual Fuel Oil | 14.79 | 14.76 | 15.07 | 15.41 | 15.77 | 16.01 | 16.26 | 16.48 | 16.68 | 16.82 | 16.93 | 16.87 |
| Natural Gas | 4.87 | 5.01 | 5.15 | 5.28 | 5.44 | 5.60 | 5.76 | 5.88 | 6.01 | 6.09 | 6.15 | 6.21 |
| Steam Coal | 2.14 | 2.15 | 2.17 | 2.19 | 2.20 | 2.23 | 2.24 | 2.26 | 2.27 | 2.29 | 2.31 | 2.32 |

| Sector and Source | 2031 | 2032 | 2033 | 2034 | 2035 | Growth Rate (2009-2035) |
|---|---|---|---|---|---|---|
| **Electric Power 9/** | | | | | | |
| Distillate Fuel Oil | 22.39 | 22.44 | 22.50 | 22.67 | 22.84 | 1.8% |
| Residual Fuel Oil | 16.86 | 16.73 | 16.75 | 16.76 | 16.71 | 2.4% |
| Natural Gas | 6.29 | 6.40 | 6.50 | 6.63 | 6.80 | 1.3% |
| Steam Coal | 2.34 | 2.35 | 2.36 | 2.38 | 2.40 | 0.3% |

**Figure D3.** World Energy Outlook 2011 fossil fuel price projection (EIA, 2012a).

## D4 EUSUSTEL

**Table 1:** Assumptions on fuel price development

| Energy Carrier | Unit | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|---|
| Coal | [EUR/GJ] | 1.96 | 1.86 | 1.97 | 2.07 | 2.14 | 2.19 |
| Lignite | [EUR/GJ] | 0.97 | 0.98 | 0.98 | 0.98 | 0.98 | 0.98 |
| Natural gas | [EUR/GJ] | 4.98 | 5.19 | 4.90 | 4.82 | 5.49 | 5.51 |
| Oil | [EUR/GJ] | 5.24 | 3.94 | 3.98 | 4.42 | 5.30 | 5.73 |
| Nuclear | [EUR/GJ] | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| Biomass | [EUR/GJ] | 3.70 | 3.70 | 3.70 | 3.70 | 3.70 | 3.70 |

**Figure D4.** EUSUSTEL fuel prices (2007e).

# D5 NEEDS

**Prices for NEEDS 2a**

**Price for Import of Fuels (basic import price to which to add the delivery cost to have the final consumer price / free power plant without taxes)**

$EURO_{2000}$ /GJ

| | 2000 | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 1.35 | 1.67 | 1.57 | 1.67 | 1.75 | 1.81 | 1.86 | 1.87 | 1.88 | 1.89 | 1.90 |
| Coke (rel coal) | 1.71 | 2.13 | 1.99 | 2.13 | 2.23 | 2.29 | 2.36 | 2.37 | 2.38 | 2.40 | 2.41 |
| Brown coal | 1.71 | 2.13 | 1.99 | 2.13 | 2.23 | 2.29 | 2.36 | 2.37 | 2.38 | 2.40 | 2.41 |
| Lignite | 1.71 | 2.13 | 1.99 | 2.13 | 2.23 | 2.29 | 2.36 | 2.37 | 2.38 | 2.40 | 2.41 |
| Crude | 4.95 | 6.51 | 5.42 | 5.42 | 5.79 | 6.63 | 7.23 | 7.31 | 7.38 | 7.45 | 7.53 |
| Heavy Distillate Oil | 4.01 | 5.27 | 4.39 | 4.39 | 4.69 | 5.37 | 5.86 | 5.92 | 5.98 | 6.04 | 6.10 |
| Light Distilate Oil | 6.44 | 8.46 | 7.05 | 7.05 | 7.52 | 8.62 | 9.40 | 9.50 | 9.59 | 9.69 | 9.78 |
| LPG | 5.45 | 7.16 | 5.97 | 5.97 | 6.37 | 7.29 | 7.96 | 8.04 | 8.12 | 8.20 | 8.28 |
| Gasoline | 6.93 | 9.11 | 7.59 | 7.59 | 8.10 | 9.28 | 10.13 | 10.23 | 10.33 | 10.43 | 10.54 |
| Kerosene | 6.93 | 9.11 | 7.59 | 7.59 | 8.10 | 9.28 | 10.13 | 10.23 | 10.33 | 10.43 | 10.54 |
| other oil products | 4.95 | 6.51 | 5.42 | 5.42 | 5.79 | 6.63 | 7.23 | 7.31 | 7.38 | 7.45 | 7.53 |
| Naphta | 4.95 | 6.51 | 5.42 | 5.42 | 5.79 | 6.63 | 7.23 | 7.31 | 7.38 | 7.45 | 7.53 |
| Feedstock | 4.95 | 6.51 | 5.42 | 5.42 | 5.79 | 6.63 | 7.23 | 7.31 | 7.38 | 7.45 | 7.53 |
| Non energy use | 4.95 | 6.51 | 5.42 | 5.42 | 5.79 | 6.63 | 7.23 | 7.31 | 7.38 | 7.45 | 7.53 |
| Natural Gas | 2.86 | 3.84 | 4.53 | 4.26 | 4.60 | 5.30 | 5.58 | 5.64 | 5.69 | 5.75 | 5.81 |
| BioWood imp | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 | 3.60 |

**Figure D5.** NEEDS fuel prices (Hirschberg, 2012).

# E Total investment cost in the reviewed studies

Tables E1-E12 presents the overnight- and total investment costs. The IEA & NEA min and max values refer to European installations. The median value is based on data from all participating OECD countries. The total investment cost figures for the median case is however not displayed in the report. CASES provide the IDC rates but not the total investment cost figures. DECC do not state the total investment cost figures in their report.

**Table E1.** Coal condensing investment cost [SEK/kW]. The EIA cost figure refers to a dual unit installation.

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| **Lignite** | | | |
| CASES | 12913 | 8,2 | ? |
| EUSUSTEL | 12913 | 5 | 14533 |
| | | 10 | 16301 |
| IEA & NEA, max | 18671 | 5 | 20902 |
| | | 10 | 23403 |
| IEA & NEA, min | 14210 | 5 | 16055 |
| | | 10 | 18117 |
| NEEDS | 13328 | 8,2 | ? |
| VGB | 12642 | - | - |
| **Hard coal** | | | |
| CASES | 9030 | 8,2 | ? |
| EUSUSTEL | 11284 | 5 | 12388 |
| | | 10 | 13561 |
| IEA & NEA, min | 13196 | 5 | 14906 |
| | | 10 | 16987 |
| IEA & NEA, max | 17164 | 5 | 18664 |
| | | 10 | 20280 |
| NEEDS, 360 MW | 11486 | 8,2 | ? |
| NEEDS, 600 MW | 9969 | 8,2 | ? |
| NEEDS, 800 MW | 8886 | 8,2 | ? |
| VGB | 11739 | - | ? |
| **Unspecified** | | | |
| Energie-Spiegel min | ? | ? | 13230 |
| Energie-Spiegel max | ? | ? | 18375 |
| DECC | 17863 | ? | ? |
| EIA | 18806 | * | ? |
| Elforsk | 14935 | 6 | 16512 |
| | | 10 | 17626 |
| IEA & NEA, median | 14423 | 5 | ? |
| | | 10 | |

**Table E2.** Combined cycle gas turbine (condensing) investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES | 4967 | 5,4 | ? |
| DECC | 7102 | - | - |
| Elforsk | 7210 | 6 | 7831 |
| | | 10 | 8264 |
| EUSUSTEL, min | 5115 | 5 | 5506 |
| | | 10 | 5908 |
| EUSUSTEL, max | 5761 | 5 | 6201 |
| | | 10 | 6654 |
| EIA, conventional | 6474 | * | ? |
| EIA, advanced | 6635 | * | ? |
| IEA & NEA, min | 6929 | 5 | 7274 |
| | | 10 | 7619 |
| IEA & NEA, max | 10965 | 5 | 12006 |
| | | 10 | 13128 |
| IEA & NEA, median | 10039 | 5 | ? |
| | | 10 | |
| Energie-Spiegel min | ? | ? | 6615 |
| Energie-Spiegel max | ? | ? | 10290 |
| NEEDS, 400 MW | 4930 | 5,4 | ? |
| NEEDS, 800 MW | 4930 | 5,4 | ? |
| VGB | 7224 | - | - |

**Table E3.** Combined cycle gas turbine (CHP) investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES | 6159 | 5,4 | ? |
| Elforsk, 150 MW | 9785 | 6 | 10819 |
| | | 10 | 11548 |
| Elforsk, 40 MW | 12875 | 6 | 14236 |
| | | 10 | 15196 |
| EUSUSTEL, BT | 5314 | 5 | 5719 |
| | | 10 | 6138 |
| EUSUSTEL | 4868 | 5 | 5238 |
| | | 10 | 5622 |
| IEA & NEA, min | 5327 | 5 | 5854 |
| | | 10 | 6321 |
| IEA & NEA, max | 12540 | 5 | 13054 |
| | | 10 | 16109 |

**Table E4.** Open cycle gas turbine investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES | 2781 | 4 | ? |
| EIA, conventional | 6434 | * | ? |
| NEEDS | 2807 | ? | ? |
| EIA, advanced | 4405 | * | ? |
| VGB | 5670 | - | - |

**Table E5.** Nuclear power plant investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES | 17684 | 10,8 | ? |
| Citi, low | - | - | 28783 |
| Citi, high | - | - | 32974 |
| DECC | 37806 | ? | ? |
| EIA | 35316 | * | ? |
| Elforsk | 28840 | 6 | 34807 |
| | | 10 | 39411 |
| EUSUSTEL, EPR min | 12913 | 5 | 14681 |
| | | 10 | 16651 |
| EUSUSTEL, EPR max | 16886 | 5 | 18069 |
| | | 10 | 20494 |
| Förnybart.nu | | | |
| IEA & NEA, median | 27726 | 5 | - |
| | | 10 | |
| IEA & NEA, min | 27730 | 5 | 31089 |
| | | 10 | 33949 |
| IEA & NEA, max | 39634 | 5 | 47239 |
| | | 10 | 56338 |
| IEA, WEO min | 21632 | - | - |
| IEA, WEO max | 30420 | - | - |
| Energie-Spiegel updated | ? | ? | ? |
| NEEDS | 14694 | ? | 17598 |
| SKGS* | 32960 | - | - |
| VGB | 27090 | - | - |

**Table E6.** CHP-B power plant investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES, straw | 25826 | 0 | 25826 |
| CASES, wood chips | 17383 | 0 | 17383 |
| NEEDS | 27090 | ? | ? |
| DECC | 43301 | ? | ? |
| Elforsk, 80 MW | 25750 | 6 | 28696 |
| | | 10 | 30391 |
| Elforsk, 30 MW | 35535 | 6 | 38358 |
| | | 10 | 40297 |
| Elforsk, 10 MW | 46350 | 6 | 50032 |
| | | 10 | 52561 |

**Table E7.** CHP-W power plant investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| DECC | 48567 | ? | ? |
| Elforsk | 79310 | 6 | 87184 |
| | | 10 | 92729 |

**Table E8.** Reservoir hydro investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES | 34766 | 10,8 | ? |
| DECC, < 5 MW | 47028 | ? | ? |
| DECC, 5-16 MW | 24495 | ? | ? |
| Elforsk, 90 MW | 19570 | 6 | 21792 |
| | | 10 | 23399 |
| Elforsk, 5 MW | 24720 | 6 | 26230 |
| | | 10 | 27266 |
| EUSUSTEL, min | 13906 | 5 | 17428 |
| | | 10 | 21858 |
| EUSUSTEL, max | 18873 | 5 | 23653 |
| | | 10 | 29676 |
| EIA | 14869 | * | ? |
| SKGS* | 28840 | - | - |

**Table E9.** Run-of-river hydro investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost | DR [%] | Generation cost |
|---|---|---|---|---|---|
| CASES,1 MW | 54632 | 10 | ? | 5 | 788 |
| | | | | 10 | 1424 |
| CASES, 50 MW | 34766 | 10 | ? | 5 | 676 |
| | | | | 10 | 1225 |
| EUSUSTEL, min | 8940 | 5 | 9386 | 5 | 327 |
| | | 10 | 9834 | 10 | 392 |
| EUSUSTEL, max | 13906 | 5 | 14601 | 5 | 12586 |
| | | 10 | 15297 | 10 | 12729 |
| VGB | 16254 | - | - | 10 | 271 |

**Table E10.** PV investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES, open space | 51652 | 0 | 51652 |
| | | 0 | |
| CASES, roof | 42463 | 0 | 42463 |
| DECC | 28775 | ? | ? |
| Elforsk | 51500 | 6 | 52736 |
| | | 10 | 54075 |
| EUSUSTEL, large | 44699 | 5 | 45357 |
| | | 10 | 45994 |
| EUSUSTEL, small | 54632 | 5 | 55437 |
| | | 10 | 56216 |
| EIA | 31446 | * | ? |
| IEA, RM Residential | 42182 | - | ? |
| IEA, RM Commercial | 35152 | - | ? |
| IEA, RM Utility | 27851 | - | ? |
| IEA & NEA, min | 40600 | 5 | 41601 |
| | | 10 | 42581 |
| IEA & NEA, max | 45644 | 5 | 46772 |
| | | 10 | 47874 |
| IEA & NEA, median | 40601 | 5 | ? |
| | | 10 | |
| Energie-Spiegel min | ? | ? | 36750 |
| Energie-Spiegel max | ? | ? | 58800 |
| NEEDS | ? | ? | ? |
| VGB, case 1 | 23478 | - | - |
| VGB, case 2 | 28896 | - | - |

**Table E11.** Wind power onshore investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES | 9933 | 0 | 9933 |
| DECC, < 5 MW | 16437 | - | - |
| DECC, > 5 MW | 16182 | - | - |
| EIA | 16128 | * | ? |
| Elforsk, 1*1 MW | 13905 | 6 | 14239 |
| | | 10 | 14461 |
| Elforsk, 5*2 MW | 13905 | 6 | 14322 |
| | | 10 | 14600 |
| Elforsk, 20*3 MW | 15450 | 6 | 16203 |
| | | 10 | 16717 |
| EUSUSTEL, 1*0,75 MW | 7946 | 5 | 8142 |
| | | 10 | 8335 |
| EUSUSTEL, 1*2 MW | 8940 | 5 | 9216 |
| | | 10 | 9397 |
| EWEA min | ? | ? | 10728 |
| EWEA max | ? | ? | 13653 |
| IEA & NEA, min | 14034 | 5 | 14385 |
| | | 10 | 14723 |
| IEA & NEA, max | 25120 | 5 | 25742 |
| | | 10 | 26350 |
| IEA & NEA, median | 15877 | 5 | ? |
| | | 10 | |
| IEA, WEO min | 11965 | - | - |
| IEA, WEO max | 13250 | - | - |
| Energie-Spiegel min | ? | ? | 13230 |
| Energie-Spiegel max | ? | ? | 18375 |
| SKGS | 15450 | - | - |
| VGB, case 1 | 9933 | - | - |
| VGB, case 2 | 11739 | - | - |

**Table E12.** Wind power offshore investment cost [SEK/kW].

| Study | Overnight investment cost | IDC [%] | Total investment cost |
|---|---|---|---|
| CASES | 16390 | 0 | 16390 |
| DECC, > 100 MW | 28902 | ? | ? |
| DECC, > 50 MW | ? | ? | ? |
| EIA | 41726 | * | ? |
| Elforsk, 50*3 MW | 23690 | 6 | 24995 |
| | | 10 | 25893 |
| Elforsk, 75*5 MW | 25750 | 6 | 27497 |
| | | 10 | 28714 |
| EUSUSTEL, 2 MW min | 15397 | 5 | 16166 |
| | | 10 | 16936 |
| EUSUSTEL, 2 MW max | 17382 | 5 | 18252 |
| | | 10 | 19121 |
| EWEA min | ? | ? | 14629 |
| EWEA max | ? | ? | 26331 |
| IEA & NEA, min | 23417 | 5 | 23998 |
| | | 10 | 24559 |
| IEA & NEA, max | 41121 | 5 | 41325 |
| | | 10 | 42299 |
| IEA, WEO min | 19536 | - | - |
| IEA, WEO max | 21632 | - | - |
| Energie-Spiegel min | ? | ? | 19845 |
| Energie-Spiegel max | ? | ? | 29400 |
| NEEDS | 19504 | ? | ? |
| VGB, near 1 | 18060 | - | - |
| VGB, near 2 | 19866 | - | - |
| VGB, far 1 | 23478 | - | - |
| VGB, far 2 | 28896 | - | - |

# F Levelised O&M cost

**Table F1.** Levelised O&M cost for non-renewable power plants [SEK/MWh$_e$]. The total O&M cost in the EIA study is only reported as a fixed and a variable cost and not as a combined alternative. The range in some studies is due to the fact that they have several different cases (e.g. plants of different net sizes) for the same power generating technology.

| Study | CC | CCGT-C | CCGT-CHP | OCGT | NP |
|---|---|---|---|---|---|
| IEA & NEA, min | 27-37 | 9 | 26 | - | 59 |
| IEA & NEA, max | 59-60 | 53 | 104 | - | 134 |
| IEA & NEA, median | 41 | 30 | - | - | 100 |
| CASES | 79-101 | 65 | 46 | 25 | 66 |
| EUSUSTEL | 49-61 | 199 | 82 | | 58 |
| Elforsk | 60 | 47 | 59-85 | | 103 |
| NEEDS | 79-100 | 33-35 | | 67 | 57 |
| SKGS | | | | | 103 |
| DECC | 65 | 32 | - | - | 123 |
| EWEA | | | | | |
| VGB | 34 | 30 | | 29 | 69 |
| EIA | | | * | | |

**Table F2.** Levelised O&M cost for renewable power plants [SEK/MWh$_e$]. The fixed O&M cost for CHP-B plants in the DECC study (2011) is reported as a negative value (probably because of heat revenues). The range in some studies is due to the fact that they have several different cases (e.g. plants of different net sizes) for the same power generating technology.

| Study | CHP-B | CHP-W | HP | PV | WP onshore | WP offshore |
|---|---|---|---|---|---|---|
| IEA & NEA, min | - | - | - | 198 | 120 | 293 |
| IEA & NEA, max | - | - | - | 386 | 207 | 366 |
| IEA & NEA, median | - | - | - | 203 | 148 | - |
| CASES | 119-177 | | 89-149 | 603-872 | 151 | 147 |
| EUSUSTEL | | | 248-12416 | 353 | 89 | 99-149 |
| Elforsk | 164-295 | 628 | 13-31 | 309 | 113-144 | 165-206 |
| NEEDS | 284 | | | | | 134 |
| SKGS | | | 62 | | 155 | |
| DECC | 90 | 495 | 133-158 | 237 | 205 | 352-394 |
| EWEA | | | | | 141 | 156 |
| VGB | | | 22-33 | 117-144 | 182-215 | 243-357 |
| EIA | | | 68 | 81 | 64 | 188 |

# G Levelised fuel cost

**Table G1.** Levelised fuel cost [SEK/MWh$_e$]. IEA & NEA (median case), DECC and Elforsk makes no distinction between different types of coal. For IEA & NEA and CASES the cost of nuclear fuel is for the entire fuel cycle. The back-end cost for nuclear power is allocated to the O&M costs in the Elforsk study. How DECC and VGB deals with the nuclear fuel cycle is not known. EIA only presents the fuel cost together with the variable O&M cost (not possible to single out the fuel cost).

| Study | Levelised fuel cost [SEK/MWhe] | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | CCGT | Hard coal | Lignite | Nuclear fuel | CHP-B | Waste | OCGT | CHP-CCGT |
| IEA & NEA, min | 403 | 195 | 92 | 63 | - | - | - | 432 |
| IEA & NEA, max | 410 | 195 | 407 | 63 | - | - | - | 579 |
| IEA & NEA, median | 413 | 123 | - | 63 | - | - | - | - |
| CASES | 390 | 156 | 79 | 65 | 734 | - | 590 | 498 |
| DECC | 494 | 205 | - | 53 | 1085 | -1599 | - | - |
| NEEDS | 401 | | 65 | 76 | 405 | | | |
| VGB | 397 | 190 | 81 | 90 | - | - | 533 | - |
| Elforsk | 444 | 202 | - | 41 | 701-816 | -639 | - | 510-714 |

# H Total generation cost in the reviewed studies

**Table H1.** Coal condensing generation cost [SEK/MWh$_e$].

| Study | DR [%] | Generation cost | Generation cost with carbon cost |
|---|---|---|---|
| **Lignite** | | | |
| CASES | 5 | 255 | |
| EUSUSTEL | 5 | 258 | 346 |
| | 10 | 366 | 454 |
| IEA & NEA, max | 5 | 627 | 811 |
| | 10 | 773 | 957 |
| IEA & NEA, min | 5 | 265 | 424 |
| | 10 | 379 | 538 |
| NEEDS | 5 | 253 | |
| VGB | 10 | 243 | 551 |
| **Hard coal** | | | |
| CASES | 5 | 294 | |
| | 10 | 347 | |
| EUSUSTEL | 5 | 306 | 375 |
| | 10 | 388 | 457 |
| IEA & NEA, min | 5 | 344 | 503 |
| | 10 | 450 | 609 |
| IEA & NEA, max | 5 | 397 | 556 |
| | 10 | 519 | 679 |
| NEEDS, 360 MW | 5 | | |
| NEEDS, 600 MW | 5 | | |
| NEEDS, 800 MW | 5 | | |
| VGB | 10 | 397 | 641 |
| **Unspecified** | | | |
| Energie-Spiegel min | 6 | 441 | |
| Energie-Spiegel max | 6 | 492 | |
| DECC | 10 | 506 | 1013 |
| EIA | * | 635 | |
| Elforsk | 6 | 453 | |
| | 10 | 546 | |
| IEA & NEA, median | 5 | 441 | |
| | 10 | 572 | |

**Table H2.** CCGT-C generation cost [SEK/$MWh_e$].

| Study | DR [%] | Generation cost |
|---|---|---|
| CASES | 5 | 475 |
| | 10 | 502 |
| DECC | 10 | 621 |
| Elforsk | 6 | 577 |
| | 10 | 628 |
| EUSUSTEL, min | 5 | 554 |
| | 10 | 586 |
| EUSUSTEL, max | 5 | 583 |
| | 10 | 618 |
| EIA, conventional | * | 443 |
| EIA, advanced | * | 423 |
| | 5 | 544 |
| IEA & NEA, min | 10 | 584 |
| IEA & NEA, max | 5 | 636 |
| | 10 | 711 |
| IEA & NEA, median | 5 | 580 |
| | 10 | 623 |
| Energie-Spiegel min | 6 | 794 |
| Energie-Spiegel max | 6 | 838 |
| NEEDS, 400 MW | 5 | 461 |
| NEEDS, 800 MW | ? | ? |
| VGB | 10 | 569 |

**Table H3.** CCGT-CHP power plant generation cost [SEK/$MWh_e$].

| Study | DR [%] | Generation cost without heat credit | Generation cost with heat credit | Full heat credit (Elforsk) | With carbon cost & heat credit |
|---|---|---|---|---|---|
| CASES | 5 | 630 | 419 | - | |
| | 10 | 666 | 445 | - | |
| Elforsk, 150 MW | 6 | 741 | 544 | 381 | |
| | 10 | 827 | 630 | 430 | |
| Elforsk, 40 MW | 6 | 1027 | 799 | 565 | |
| | 10 | 1141 | 914 | 629 | |
| EUSUSTEL, BT | 5 | 535 | 337 | | |
| | 10 | 569 | 373 | | |
| EUSUSTEL | 5 | 393 | 207 | - | |
| | 10 | 425 | 240 | - | |
| | 5 | 509 | 259 | | 343 |
| IEA & NEA, min | 10 | 544 | 294 | | 379 |
| IEA & NEA, max | 5 | 796 | 597 | | 699 |
| | 10 | 903 | 704 | | 806 |

**Table H4.** OCGT generation cost [SEK/MWh$_e$].

| Study | DR [%] | Electricity cost | Including carbon cost |
|---|---|---|---|
| CASES | 5 | 652 | - |
| | 10 | 663 | - |
| EIA, conventional | * | 834 | - |
| NEEDS | | | |
| EIA, advanced | * | 693 | - |
| VGB | 10 | 677 | 821 |

**Table H5.** Nuclear power generation cost [SEK/MWh$_e$].

| Study | DR [%] | Generation cost |
|---|---|---|
| CASES | 5 | 290 |
| | 10 | 407 |
| Citi, low | 8,5 | 599 |
| Citi, high | 8,5 | 645 |
| DECC | 10 | 786 |
| EIA | * | 763 |
| Elforsk | 6 | 453 |
| | 10 | 680 |
| EUSUSTEL, EPR min | 5 | 240 |
| | 10 | 349 |
| EUSUSTEL, EPR max | 5 | 267 |
| | 10 | 403 |
| Förnybart.nu | | |
| IEA & NEA, median | 5 | 395 |
| | 10 | 668 |
| IEA & NEA, min | 5 | 338 |
| | 10 | 559 |
| IEA & NEA, max | 5 | 529 |
| | 10 | 923 |
| IEA, WEO min | ? | 372 |
| IEA, WEO max | ? | 541 |
| Energie-Spiegel updated | 6 | 529 |
| NEEDS | 5 | 293 |
| SKGS* | 6,5-9,25 | 304-434 |
| VGB | 10 | 569 |

**Table H6.** CHP-B generation cost [SEK/$MWh_e$].

| Study | Generation cost without heat credit | Generation cost with heat credit | Full heat credit (Elforsk) |
|---|---|---|---|
| CASES, straw | 1176 | 247 | - |
| | 1326 | 413 | - |
| CASES, wood chips | 1081 | 112 | - |
| | 1131 | 219 | - |
| NEEDS | - | 678 | - |
| DECC | - | 1474 | - |
| Elforsk, 80 MW | 1342 | 744 | 321 |
| | 1576 | 978 | 453 |
| Elforsk, 30 MW | 1582 | 943 | 407 |
| | 1882 | 1243 | 582 |
| Elforsk, 10 MW | 1926 | 1208 | 473 |
| | 2318 | 1560 | 701 |

**Table H7.** CHP-W generation cost [SEK/$MWh_e$].

| Study | DR [%] | Generation cost | Generation cost with heat credit | Full heat credit (Elforsk) |
|---|---|---|---|---|
| DECC | 10 | - | -313 | - |
| Elforsk | 5 | 906 | -75 | -856 |
| | 6 | 1017 | 35 | -791 |
| | 10 | 1526 | 546 | -473 |

**Table H8.** Reservoir hydro generation cost [SEK/$MWh_e$].

| Study | DR [%] | Generation cost |
|---|---|---|
| CASES | 5 | 1097 |
| | 10 | 2038 |
| DECC, < 5 MW | 10 | 1387 |
| DECC, 5-16 MW | 10 | 771 |
| Elforsk, 90 MW | 6 | 375 |
| | 10 | 611 |
| Elforsk, 5 MW | 6 | 472 |
| | 10 | 735 |
| EUSUSTEL, min | 5 | 2703 |
| | 10 | 2859 |
| EUSUSTEL, max | 5 | 5250 |
| | 10 | 5493 |
| WEO | * | 578 |
| SKGS* | 6,5 | 402 |

**Table H9.** ROR hydro generation cost [SEK/MWh$_e$].

| Study | DR [%] | Generation cost |
|---|---|---|
| CASES | 5 | 778-676 |
| | 10 | 1397-1224 |
| EUSUSTEL, min | 5 | 327 |
| | 10 | 392 |
| EUSUSTEL, max | 5 | 12586 |
| | 10 | 12729 |
| VGB | 10 | 271 |

**Table H10.** PV generation cost [SEK/MWh$_e$].

| Study | DR [%] | Generation cost without backup | With backup cost min | With backup cost max |
|---|---|---|---|---|
| CASES, open space | 5 | 4293 | 4381 | 4446 |
| | 10 | 6185 | 6303 | 6399 |
| CASES, roof | 5 | 3412 | 3504 | 3566 |
| | 10 | 4971 | 5089 | 5183 |
| DECC | 10 | 3337 | - | - |
| Elforsk | 6 | 5366 | - | - |
| | 10 | 6891 | - | - |
| EUSUSTEL, large | 5 | 2480 | 2574 | 2644 |
| | 10 | 4065 | 4199 | 4313 |
| EUSUSTEL, small | 5 | 3005 | 3100 | 3170 |
| | 10 | 4921 | 5056 | 5169 |
| EIA | * | 1410 | - | - |
| IEA, RM Residential | 10 | 2507-5013 | - | - |
| IEA, RM Commercial | 10 | 2089-4178 | - | - |
| IEA, RM Utility | 10 | 1671-3342 | - | - |
| IEA & NEA, min | 5 | 1654 | - | - |
| | 10 | 2441 | - | - |
| IEA & NEA, max | 5 | 4237 | - | - |
| | 10 | 6318 | - | - |
| IEA & NEA, median | 5 | 2777 | - | - |
| | 10 | 4168 | - | - |
| Energie-Spiegel min | 6 | 3087 | - | - |
| Energie-Spiegel max | 6 | 4851 | - | - |
| NEEDS | 5 | 4879 | 4989 | - |
| VGB, case 1 | 10 | 1544 | - | - |
| VGB, case 2 | 10 | 1869 | - | - |

**Table H11.** Wind power onshore generation cost [SEK/$MWh_e$].

| Study | DR [%] | Generation cost without back up | With backup cost min | With backup cost max |
|---|---|---|---|---|
| CASES | 5 | 454 | 542 | 607 |
| | 10 | 595 | 713 | 809 |
| DECC, < 5 MW | 10 | 1114 | - | - |
| DECC, > 5 MW | 10 | 958 | - | - |
| EIA | * | 649 | - | - |
| Elforsk, 1*1 MW | 6 | 582 | - | - |
| | 10 | 755 | - | - |
| Elforsk, 5*2 MW | 6 | 582 | - | - |
| | 10 | 745 | - | - |
| Elforsk, 20*3 MW | 6 | 605 | - | - |
| | 10 | 785 | - | - |
| EUSUSTEL, 1*0,75 MW | 5 | 351 | 442 | 510 |
| | 10 | 482 | 612 | 724 |
| EUSUSTEL, 1*2 MW | 5 | 457 | 546 | 612 |
| | 10 | 640 | 767 | 875 |
| EWEA min | 7,5 | 517-848 | - | - |
| EWEA max | 7,5 | 605-1044 | - | - |
| IEA & NEA, min | 5 | 578 | | - |
| | 10 | 825 | - | - |
| IEA & NEA, max | 5 | 1101 | - | - |
| | 10 | 1584 | - | - |
| IEA & NEA, median | 5 | 654 | - | - |
| | 10 | 928 | - | - |
| IEA, WEO min | ? | 608 | - | - |
| IEA, WEO max | ? | 710 | - | - |
| Energie-Spiegel min | 6 | 1573 | - | - |
| Energie-Spiegel max | 6 | 1948 | - | - |
| SKGS | 6,5 | 664 | - | - |
| VGB, case 1 | 10 | 831 | - | - |
| VGB, case 2 | 10 | 966 | - | - |

**Table H12.** Wind power offshore generation cost [SEK/$MWh_e$].

| Study | DR [%] | Generation cost | With backup cost min | With backup cost max |
|---|---|---|---|---|
| CASES | 5 | 473 | 564 | 631 |
| | 10 | 624 | 747 | 857 |
| DECC, > 100 MW | 10 | 1292 | - | - |
| DECC, > 50 MW | 10 | 1566 | - | - |
| EIA | * | 1628 | | |
| Elforsk, 50*3 MW | 6 | 893 | - | - |
| | 10 | 1181 | - | - |
| Elforsk, 75*5 MW | 6 | 985 | - | - |
| | 10 | 1302 | - | - |
| EUSUSTEL, 2 MW min | 5 | 396 | 492 | 565 |
| | 10 | 553 | 692 | 810 |
| EUSUSTEL, 2 MW max | 5 | 725 | 817 | 886 |
| | 10 | 1033 | 1164 | 1276 |
| EWEA min | 7,5 | 575 | - | - |
| EWEA max | 7,5 | 878 | - | - |
| IEA & NEA, min | 5 | 817 | - | - |
| | 10 | 1101 | - | - |
| IEA & NEA, max | 5 | 1272 | - | - |
| | 10 | 1763 | - | - |
| IEA, WEO min | ? | 676 | - | - |
| IEA, WEO max | ? | 811 | - | - |
| Energie-Spiegel min | 6 | 809 | | |
| Energie-Spiegel max | 6 | 956 | | |
| NEEDS | 5 | 681 | 791 | - |
| VGB, near 1 | 10 | 898 | - | - |
| VGB, near 2 | 10 | 1029 | - | - |
| VGB, far 1 | 10 | 1057 | - | - |
| VGB, far 2 | 10 | 1174 | - | - |

# I Assumptions on input parameters used in the LCOE model

**Table I1.** Input parameters for non-renewables.

| Input parameter | Hard coal | Lignite | CCGT-C | CCGT-CHP | OCGT | Nuclear |
|---|---|---|---|---|---|---|
| Net el power [MW] | 558 | 870 | 549 | 215 | 99 | 1403 |
| Net el efficiency (LHV) [%] | 46 | 44 | 58 | 46 | 38 | 36 |
| Net thermal efficiency [%] | | | | 90 | | |
| Net heat power [MW] | | | | 206 | | |
| Capacity factor | 0,85 | 0,85 | 0,85 | 0,85 | 0,3 | 0,87 |
| Lifetime [years] | 35 | 35 | 28 | 28 | 30 | 40 |
| Discount rate | | | 10% | | | |
| Overnight cost [SEK/kWe] | 11385 | 13121 | 6635 | 6159 | 4405 | 27730 |
| O&M cost [SEK/MWhe] | 60 | 60 | 34 | 71 | 29 | 100 |
| Fuel price [SEK/MWhf] | 90 | 35 | 320 | 320 | 320 | 14 |
| Carbon price | | | 173 SEK/tonne | | | |
| Heat credits | | | 239 SEK/MWhh | | | |
| Construction period | 4 | 4 | 3 | 3 | 2* | 6 |
| Interest during construction | | | Same as the discount rate | | | |
| Cost outlays during construction | | | Linear | | | |
| Emissions [tonne/MWhf] | | | | | | |
| C emission natural gas | 0,202 | | | | | |
| C emission hard coal | 0,341 | | | | | |
| C emission lignite | 0,364 | | | | | |

**Table I2.** Input parameters for renewables.

| Input parameter | CHP-B | CHP-W | HP | PV | WP on | Wp off |
|---|---|---|---|---|---|---|
| Net el power [MW] | 26 | 20 | 349 | 0,95 | 2,1 | 3,1 |
| Net el efficiency (LHV) [%] | 23 | 19 | - | - | - | - |
| Net thermal efficiency [%] | 96 | 99 | | | | |
| Net heat power [MW] | 83 | 84 | | | | |
| | | | | | | |
| Capacity factor | 0,81 | 0,79 | 0,52 | 0,13 | 0,26 | 0,37 |
| Lifetime [years] | 28 | 27 | 50 | 25 | 20 | 20 |
| | | | | | | |
| Discount rate | 10% | | | | | |
| | | | | | | |
| Overnight cost [SEK/kWe] | 27090 | 63939 | 24495 | 40601 | 13905 | 22525 |
| O&M cost [SEK/MWhe] | 171 | 562 | 101 | 203 | 146 | 243 |
| | | | | | | |
| Fuel price [SEK/MWhf] | 210 | -120 | - | - | - | - |
| Carbon price | 173 SEK/tonne | | | | | |
| Heat credits | 239 SEK/MWhh | | | | | |
| | | | | | | |
| Construction period | 2 | 3 | 4 | 1 | 2 | 3 |
| Interest during construction | Same as the discount rate | | | | | |
| Cost outlays during construction | Linear | | | | | |

# J LCOE model setup (hard coal power plant)

| LCOE model | | | | |
|---|---|---|---|---|
| El capacity (MW) | 558 | | | |
| Capacity factor | 0,85 | | | |
| Full load hours | 7446 | | | |
| El production [MWh] | 4154868 | | | |
| | | | | |
| El efficiency [%] | 46 | | | |
| Th efficiency [%] | 0 | | | |
| Heat capacity [MW] | 0 | | | |
| Carbon dioxide emissions [tonne/MWhf] | 0,341 | | | |
| | | | | |
| Overnight investment [SEK/kWe] | 11385 | | | |
| Fuel price [SEK/MWhf] | 90 | | | |
| Carbon price [SEK/tonne] | 173 | | | |
| Heat credit [SEK/MWhf] | 173 | | | |
| O&M cost [SEK/MWhe] | 60 | | | |
| | | | | |
| Discount rate [%] | 10 | | | |
| Year [t] | 0 | 1 | 2 | 3 |
| Discount rate [r] | 0,1 | 0,1 | 0,1 | 0,1 |
| Discount factor ((1+r)^t) | 1 | 1,1 | 1,21 | 1,331 |
| | | | | |
| Total investment (with IDC) [SEK/kWe] | 14530 | | | |
| O&M cost [SEK/MWhe] | 60 | | | |
| Fuel cost [SEK/MWhe] | 196 | | SEK/MWhe | |
| Carbon cost [SEK/MWhe] | 128 | Total | Investment | Fuel |
| Heat revenue [SEK/MWhe] | 0 | 568 | 184 | 196 |
| | | | | |
| Fuel price escalation [%] | 0 | O&M | Carbon | Heat credit |
| O&M cost escalation [%] | 0 | 60 | 128 | 0 |
| Carbon price escalation [%] | 0 | | | |
| | | | | |
| Degradation [%] | | | | |
| | | | | |
| Discounted investment cost [SEK] | 8,11E+09 | | | |
| Discounted O&M cost in year t [SEK] | 249292080 | 226629164 | 206026512 | 187296829 |
| Discounted fuel cost in year t [SEK] | 812908957 | 739008142 | 671825584 | 610750531 |
| Discounted carbon cost in year t [SEK] | 532843756 | 484403415 | 440366741 | 400333401 |
| Discounted heat revenues in year t [SEK] | 0 | 0 | 0 | 0 |
| | | | | |
| Yearly discounted costs [SEK/MWhe] | 9,70E+09 | 1450040721 | 1318218837 | 1198380761 |
| Total discounted costs [SEK] | 2,50E+10 | | | |

| | | | | |
|---|---|---|---|---|
| Yearly discounted production [MWhe] | 4154868 | 3777153 | 3433775 | 3121614 |
| Total discounted production [MWhe] | 4,41E+07 | | | |
| | | | | |
| **Levelised cost result** | | | | |
| LCOE [SEK/MWhe] | 568 | | | |
| | | | | |
| **Interest during construction (IDC)** | | | | |
| Overnight cost [SEK/kWe] | 11385 | | | |
| Interest during construction | 0,1 | | | |
| years to construction | 10 | 9 | 8 | 7 |
| Allocation of interest [%] | | | | |
| | 0 | 0 | 0 | 0 |
| Total interest expense [SEK/kWe] | 3145 | | | |

**Figure J1.** LCOE model setup (hard coal power plant).