*SIXTH FRAMEWORK PROGRAMME*

Project no: **502687**

**NEEDS**

**New Energy Externalities Developments for Sustainability**

**INTEGRATED PROJECT**

*Priority 6.1: Sustainable Energy Systems* and, more specifically,
*Sub-priority 6.1.3.2.5: Socio-economic tools and concepts for energy strategy.*

# Deliverable D 3.3 - RS 1a

# Cost development – an analysis based on experience curves

Due date of deliverable: 31 August 2006 (M24)
Actual submission date:

Start date of project: 1 September 2004
Duration: 48 months

Organisation name for this deliverable: Lund University

| Project co-funded by the European Commission within the Sixth Framework Programme (2002-2006) | | |
|---|---|---|
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## Contents

## Preface

This report is part of the NEEDS project and more specifically the result of WP3, RS1a. The objective of the work has been to develop a framework for the analysis of future cost development paths of new energy technologies or technology areas used to generate electricity. The approach applied is based on experience curves supported by additional and less aggregated methods for estimating technology development. The result of the work of this report, i.e. different experience curves for different energy technologies or technology areas, will be used as input in RS1a and RS2a and the modelling of different scenarios for future energy systems.

The work presented in this report has been performed by Lena Neij (Lund University, Sweden) in cooperation with Mads Borup (Risø National Laboratory, Denmark) Markus Blesl and Oliver Mayer-Spohn (Institut für Energiewirtschaft und Rationelle Energieanwendung, Germany). The text describing technology development and cost figures has been reviewed by the technology experts of RS1a; the advanced fossil fuel technology chapter has been reviewed by Roberto Dones, Christian Bauer and Thomas Heck (Paul Scherrer Institut, Switzerland); the advanced nuclear chapter has been reviewed by Claude Garzenne, Agathe Le Bocq, Denis Le Boulch (Electricité de France, France) and Roberto Dones (Paul Scherrer Institut, Switzerland); the fuel cell chapter has been reviewed by Raffaella Gerboni, Evasio Lavagno (Politecnico di Torino), Martin Pehnt (Institut für Energie- und Umweltforschung Heidelberg GmbH, Germany) and Peter Viebahn (Deutsches Zentrum für Luft- und Raumfahrt e.V., Germany); the wind turbine chapter has been reviewed by Kim Winther, Abdi Ashur Hassan and Henriette Hassing Corlin (Elsam A/S, Denmark); the PV chapter has been reviewed by Paolo Frankl, Emanuela Menichetti, Giacomo Prennushi and Simona Lombardelli (Ambiente Italia srl, Italy); the chapter on solar thermal power plants has been reviewed by Stefan Kronshage, Peter Viebahn (Deutsches Zentrum für Luft- und Raumfahrt e.V., Germany), Yolanda Lechon (Centro de Investigaciones Energeticas, MediAmbientales y Technologicas, Spain); the bioenergy technology chapter has been reviewed by Sven Gärtner (Institute for Energy and Environmental Research Heidelberg, Germany); and the hydrogen chapter has been reviewed by Maria Maack (Icelandic New Energy, INE).

## Abstract

As part of the NEEDS project, the objective of this report is to develop an analytical framework for the analysis of future cost development of new energy technologies. The focus is on technologies used to generate electricity, and the approach used is based on experience curves complemented with bottom-up studies of sources of cost reductions and, for some technologies, judgmental expert assessments on long-term development paths. The additional methods, which provide less aggregated and more detailed information on cost development paths, will be used to critically evaluate the cost reduction path described by the experience curves. The three methodological approaches should not be seen as three distinct analyses. They will to some extent overlap.

In all, the result of the critical review of the experience curves studies, the bottom-up analysis and the judgmental expert assessments agree in most cases; the cost reductions illustrated by the experience curves match with the incremental cost reduction described in the bottom-up analysis and the judgmental expert assessments. Only one exception is found; in the case of nuclear the experience curve illustrates a cost increase whereas the bottom-up approach illustrates a cost stabilisation. Altogether, experience curves with progress ratios ranging from 80-100% are suggested. For some technologies, the bottom-up analysis confirms large uncertainties in future cost development not captured by the experience curves. To underline the uncertainty of the cost reduction we suggest the use of a sensitivity range of the progress ratio of the experience curve.

# 1. Introduction

## 1. 1 Background

The transition towards a sustainable energy system will require the development and deployment of new and improved energy technologies. Such technologies often have a higher cost than traditional energy technologies and to be implemented the cost of these new technologies needs to be reduced. To make decisions in future investments and design of energy systems, analysis of technology and cost development is required. This, in turn, calls for methods of analysing the dynamics of energy systems in regard to technical change and cost development. Moreover, decision support tools like complex energy models need to take into account technical change and cost development.

Experience curves provide a tool for analysing future cost development. In general, experience curves have been used to analyse historical cost trends of various technologies, to estimate future cost development and as a tool for strategic business analysis. The use of experience curves for energy technology cost development has become increasingly more common and today these are also integrated in complex energy models to endogenously analyse cost development.

Several advantages in using experience curves have been identified. Firstly, experience curves illustrate the approximate rate of cost reduction for different types of energy technologies. It has been shown that the expected cost reduction will depend on the modularity of the product (Neij, 1999). The cost of smaller and modular products tends to decrease more rapidly than the cost of non-modular units or plants. The justification seems to be that the opportunities given to improve technology, to incorporate scale effects and to reduce cost, are more frequent for the production of smaller and modular products than for huge plants. Secondly, the integration of experience curves into energy models has improved the possibility of integrating technology change into energy system analysis and scenario planning (Mattson and Wene, 1997; Messner, 1997). The results of such analysis show the benefits of early investment in emerging technologies that are not competitive with traditional energy technologies today. Thirdly, experience curves clearly illustrate the need for an initial market in order to cut costs. An initial market will provide opportunities for learning (learning-by-doing and learning-by-using) which, in turn will lead to cost reductions. It can ensure a productive degree of experimentation, variety and competition between solutions. Such markets could be developed through early adopters, niche markets, or governmental policy measures that support market expansion. Over time, new products with a high initial cost will be competitive to other already established technologies.

At the same time, several weaknesses in using experience curves have been identified and the use of experience curves for analysing cost development have been criticised (see for example Neij, 2003 and Nemet, 2005). Firstly, the interpretation of the experience curve concept as a tool for cost development has extended over time. Historically, experience curves, or learning curves, were used to analyse the reduction in man-hours (or cost) per unit of a standardised product produced by an individual company. Today, experience curves are used for cost analysis and cost forecasts of non-standardised products produced globally or nationally. This provides uncertainties and varieties in results not often considered in experience curve analysis. Although the uncertainties and varieties in cost development may affect the outcome of any analysed energy system design considerably. Secondly, the driving forces of the cost reduction are uncertain. The use of the experience curve concept is based on an aggregated approach of analysing cost reductions. Some experts argue that this does not make sense – but each source of cost reduction must be identified and analysed separately (see for example Krawiec et al., 1980; Hall and Howell, 1985, and Nemet, 2005). Thirdly, experience curves are used to forecast long-term cost development. However, this is not appropriate since the experience curve is a trend analysis tool, and only suitable for the analysis of established technologies and forecasts of short time ranges, i.e. 5-10 years. It is also important to note, that the use of experience curves, and similar trend analysis tools, is only suitable under conditions of low uncertainty and for series of incremental innovations. Trend analysis tools are not suitable for prospective analysis under conditions characterised by high uncertainty or shifts in technology and market situations.

In all, the critique articulates the need of complementary tools when using experience curves for long-term forecasting of cost development and future energy systems. One complementary approach would be to use methods describing the sources of cost reduction and how and why costs will be reduced. Such methods can be said to be based on bottom-up analysis of technology and cost developments. To further support a long-term analysis of cost development, we are left with judgemental methodologies such as interviews with experts and expert panels.

## 1. 2 Objective

As part of the NEEDS project RS1a WP3 we are to develop an analytical framework for the analysis of future cost development of new energy technologies or technology areas. The focus in RS1a is on technologies used to generate electricity. The approach to be used will be experience curves, however, complemented with additional methods to improve the quality and validity of the results. In addition to experience curves, bottom-up studies of cost reductions will be included to support the analysis of sources of cost reduction and, for some technologies, judgmental expert assessments will be applied to support long-term development paths. These additional methods, which provide less aggregated information on cost development paths, will be used to critically evaluate the cost reduction path described by the experience curves.

First, cost development will be analysed and discussed based on experience curves. For each technology area studies based on experience curves will be collected and a critical analysis of the data in these studies will be performed. The progress ratio of the experience curves will indicate future cost reductions.

Second, cost development will be analysed and discussed based on reports on bottom-up analysis of sources of cost reduction. Reports covering historical and future analysis of sources of cost reduction have been collected, critically analysed and used to discuss future possible sources of cost reduction. The reports cover detailed technical analysis as well as roadmaps including additional drivers of cost reduction.

Third, cost development paths, for some technologies, will be analysed and discussed based on judgmental methods building on expert assessments. In general such methods include expert panels, scenario developments, brainstorm exercises and vision paper writing. In addition, direct contact with experts in the energy technology area can be used as a method approach. The direct contact can be through interviews and scenario workshops. In the work presented in this report, expert assessments have been obtained through interviews.

The three methodological approaches should not be seen as three distinct analyses, but they will to some extent overlap. However, the integration of them can provide genuine and robust results describing future cost development of energy technologies. In the report the differences in the results using different approaches will be discussed and recommendations for what "experience curve" to use as input in RS1a and RS2a will be specified.

# 2. Experience curves

## 2.1 Introduction to the experience curve concept

Experience curves have been used for several decades to analyse the cost reduction of new technologies. The concept of experience curves is based on learning curves, which have been used to analyse the reduction in man-hours (or cost) per unit of a standardised product produced by an individual company. (For the first publication on technological learning, see Wright (1936); for a recent survey, see Argote and Epple (1990)). Experience curves have, however, come to be used in a more general way than learning curves, and refer to cost reductions for non-standardised products produced globally, nationally, or by an individual company (Arrow, 1962; BCG, 1972; Abell and Hammond, 1979). The cost reduction refers to the total cost (labour, capital, administrative costs, research and marketing costs, etc.), and sources of cost reduction include cost reductions due to changes in production (process incremental innovations, learning effects and scaling effects), changes in the product (product incremental innovations, product redesign and product standardisation), changes in input prices and, actually, changes in the entire socio-technical system. Due to this, experience curves ought to be used with care.

The experience curve describes how unit costs decline with cumulative production[1], see Figure 2.1. A specific characteristic of an experience curve is that the cost decreases by a constant percentage with each doubling of the total number of units produced. Generally, the curve is expressed as:

$$C_{CUM} = C_0 \cdot CUM^{b}$$

where $C_{CUM}$ is the cost per unit as a function of output, $C_0$ is the cost of the first unit produced, CUM is the cumulative production over time, and b is the experience index. The experience index is used to calculate the relative cost reduction, ($1-2^{b}$), for each doubling of the cumulative production.[2] The value ($2^{b}$), which is called the progress ratio (PR), is used to express the progress of cost reductions for different technologies. A progress ratio of 80%, for example, means that costs are reduced by 20% each time the cumulative production is doubled.

The concept of experience curves should not be regarded as an established theory or method, but rather as a correlation phenomenon, which has been observed for several technologies. The observed progress ratios for different technologies cover a range from 64% to over 100%. It has been shown that cost may not always decrease with cumulative production but may also increase (progress ratio >100%). Therefore, it is important to point out that experience *per se* does not cause cost reductions, but rather provides opportunities for cost reductions. An increasing progress ratio may arise when, for example, the total cost cannot be reduced (by product standardisation, process specialisation, scale effects, labour rationalisation, etc.) as

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1 Instead of cumulative produced units one could use cumulative sold units or cumulative installed units.

2 For each doubling of the cumulative production ($CUM_2 = 2\mathrm{CUM}_1$) the relative cost reduction will be $\frac{C_{CUM1} - C_{CUM2}}{C_{CUM1}} = 1 - \frac{C_0 \cdot (2\,CUM_1)^{b}}{C_0 \cdot CUM_1{}^{b}} = 1 - 2^{b}$

fast as costs are incurred through design changes and product performance improvements. Moreover, an increasing progress ratio may illustrate a limitation in using experience curves to analyse cost trends of non-standardised products.

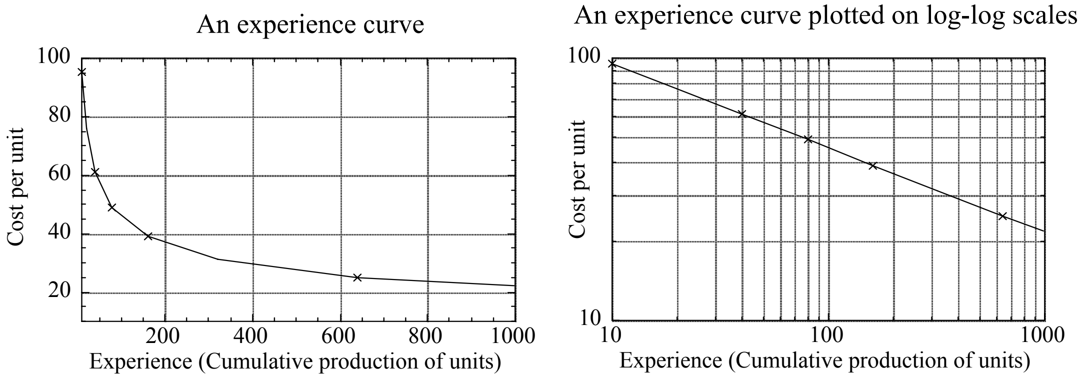


Figure 2.1 An experience curve with a progress ratio of 80%.

Furthermore, the cost reductions illustrated by the experience curve method do not always follow a straight line; it has been observed that some experience curves show discontinuities, or a distinct break, see Figure 2.2. Such discontinuities may be the result of a pricing strategy (e.g. price reduction levels off at a different rate than the cost reduction, see, for example, Boston Consulting Group (BCG), 1972) or changes in the market or the market demand. Discontinuities may also be the result of technological development. If the development in technology could be described by marginal and incremental improvements such improvements will not cause a discontinuity in the experience curve. If, however, technology development results in major changes (radical improvements), a discontinuity or a break may appear in the experience curve. It could be discussed, however, whether such a break calls for the use of two separate experience curves. One problem is that the distinction between marginal and major changes is subtle and often somewhat arbitrary.

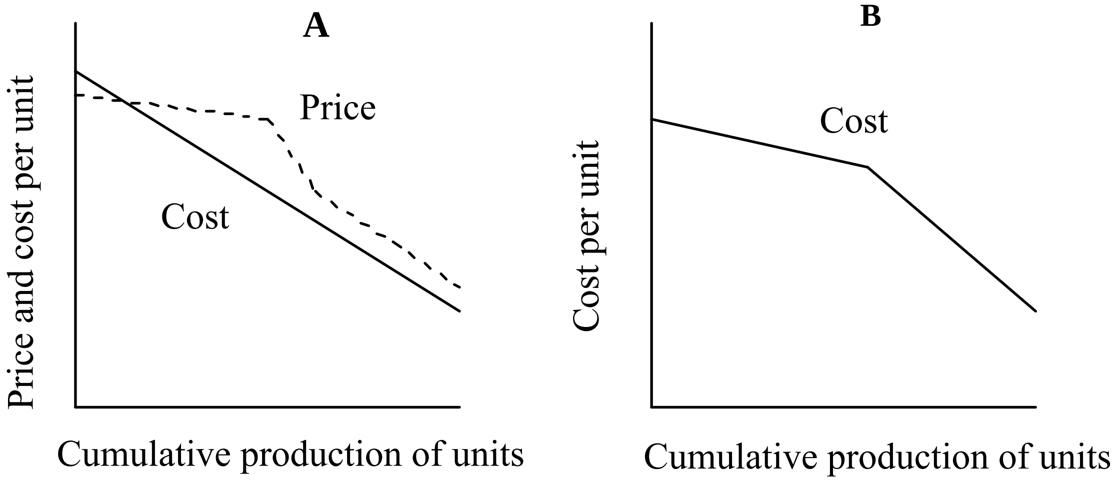


Figure 2.2. Discontinuities in the experience curve (log-log scales) due to (A) a non-idealised price-cost relationship and (B) radical improvements in the technology (innovation).

The phenomenon of discontinuities is highly interesting and naturally an issue that attracts continuous attention. Despite the above-mentioned points, a complete explanation of the phenomenon has not been given. Newer studies of socio-technical change processes and innovation studies building on evolutionary economics suggest that some of the explanation can be found not in the perspective of the single product and the single company that classical experience curve terminology favours but in between the companies and the other actors involved in a field. The network relations between a larger number of actors and dynamics that structure the interplay between the actors are of significant importance to the development. This includes for example, firstly, industrial networks, sub-contractor systems, market creations, and advanced articulations of needs and demands. Secondly, it includes innovative knowledge networks and clusters of actors, efficiency in innovation systems and the knowledge production.

Not only the maturity of a product, but the maturity of an industrial area and its' innovative capability is needed. Diversity and variety between the actors is a key issue here. It enables the competition and the efficient development processes competition can ensure. This is one of the reasons why an initial market, as mentioned in the introduction, is needed. This can e.g. be in the shape of niche markets, lead users, and market development through public support.

## 2.2 The use of experience curves for extrapolating future cost development

The historical trend in cost reductions expressed by experience curves has been extrapolated and used to analyse future cost reductions. Such an analysis must, however, take into account possible large variations in the progress ratio for a non-standardised product. The progress ratio should therefore be expressed as a range, rather than as a specific value. Moreover, the uncertainty and diversification embedded in the experience curve limits any prediction of future cost. For this reason experience curves should rather be used to provide guidance of future cot development and insight into the capabilities and limitations of the further diffusion and adoption of new technologies than for forecasting future costs.

## 2.3 Experience curves and system boundaries

Experience curves can be developed according to different *system approaches* that can be used, describing different parts of a technology system. (Here we are working with a technical definition of the system. Also a socio-technical system approach could be applied integrating the entire innovation system, industrial clusters and networks etc.). To give an example the wind system could be divided into components, wind turbines, installed wind turbines, wind-generated electricity etc. When analysing cost reduction of wind power it is important to realize that the learning system of wind power is an aggregated system of several individual learning systems, see Figure 2.3. One system is the learning system of wind turbines. This system can be divided into learning systems of components such as blades, towers etc. The learning system of wind turbines can however be extended to a learning system of installed wind turbines including foundations, installation, site preparation, land acquisition, grid connection, necessary infrastructure such as roads, transmission lines etc. Moreover, another dimension is the learning associated with wind turbine performance and the expected increase in wind capture and electricity generated. The learning system of wind power is thus an aggregated learning system including the learning systems associated with wind turbines (as described above), siting and wind capture and maintenance. Experience curves for other energy technologies and energy generated could similarly be divided into systems and subsystems covering components, technologies and clusters of technologies etc.

The development of experience curves using different system boundaries, as described above, will give rise to different progress ratios. Moreover, the progress ratio will depend on the time frame used – for most technologies the cost will not be reduced constantly. Another reason for variation in the progress ratio can be the size of technologies included. If including different size segments different cost reduction patterns could be observed.

It is important to notice that constructing reliable experience curves requires a high degree of "data discipline". Experience curves cannot be better than the raw data from which they are constructed. Only experience curve studies that provide evidence of their validity, reliability and relevance should be taken into account in policy-making.

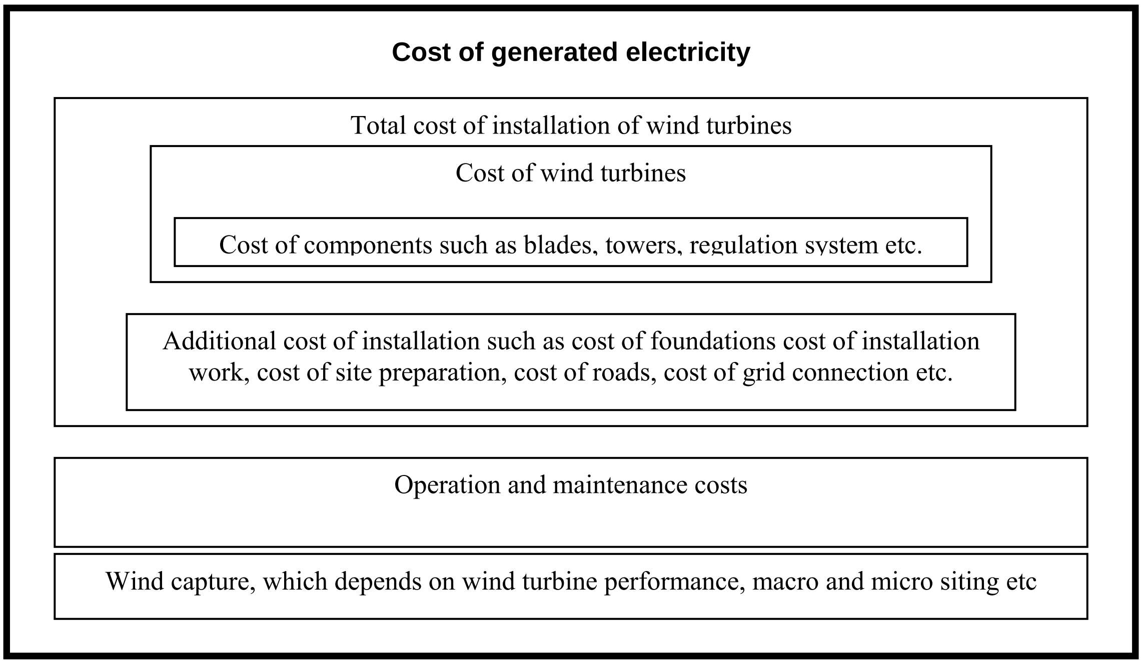


Figure 2.3 Aggregated system of wind power divided into several sub-systems. Experience curves can be constructed for each sub-system.

## 3. Bottom-up assessments

In this report we apply bottom-up assessments to complement the experience curve analysis in defining and describing future cost development of energy technologies. The bottom-up assessments do not refer to a specific methodological approach but cover reports written by individuals, research groups, industries or others to describe sources of cost reduction. The studies could either have a historical approach describing the reasons for actual cost reductions, or they can have a future oriented approach identifying and analysing potential sources of cost reduction in the future. Moreover, the reports could be very technical describing and comparing alternative technical concepts, of they could be much wider and consider additional drivers and sources of cost reduction. Such wider analysis will be covered in roadmaps.

The advantage of complementing the experience curves with bottom-up assessments will be to identify the actual sources of cost reduction. Due to this limitations and discontinues in further cost reduction can be identified. Analysis of cost reduction applying experience curves and the extrapolation of experience curves are based on the assumption that the development of the technology is incremental and continuous and will be so also in the future. Moreover, it does not take into consideration any physical limitations or changes in the market. By the identification of and analysis of different sources of cost reduction, the experience curves could be modified, or the uncertainty of future cost reduction stressed. For example, identified radical technology changes and cost development paths could be illustrated applying a discontinuity, or a distinct break, in the experience curve.

The analysis based on bottom-up assessments will most often improve with the number of reports. The more reports, the more insight will be given form different actors with different perspectives. Important to keep in mind will be that experts often promote “their own” technologies.

## 4. Long-term expert assessments

A third approach in the analytical work is analysis based on expert assessments and opinions. This approach builds on the recognition that experts involved in an energy technology area have deep and in many ways unsurpassed insight in the field and in its development dynamics. This is obvious, almost by definition, when talking about the experts' specific and more or less narrow subfield within the energy technology area. However, it also is the case concerning the broader understanding of the area and its coherence. For example, an expert who has been working ten years specifically with combustion techniques within the biomass area usually also have good insight in, e.g., the overall planning and economy of biomass power plants, in issues of crop production, etc.

The experts' understanding of their field is unique in its richness and comprehensiveness. Assessments of possible future costs by the experts can be more substantial and reflective than many other analyses including e.g. some experience curve descriptions. Moreover, experts can offer highly qualified interpretations and evaluations of existing analyses of the future. They can often with a few words pinpoint the central aspects and strong and weak elements in suggested descriptions of the future technology systems.

Large parts of the experts' knowledge are most of the time implicit and unarticulated and it is impossible for the experts to give a 100% complete and correct account of it ('tacit knowledge', Polanyi, 1966). In this sense the experts are bound to the traditions for analysis and knowledge communication that exist within their specific subfield. However if one asks in certain ways it is often possible to make the experts consider issues they are maybe not used to be articulate about, e.g. the future costs.

In recent years, a number of systematic methods for analysing and discussing possible future developments of a field have been developed. Many of these methods build largely on expert assessments: they identify different experts' expectations about future developments and integrate and discuss these views. In connection with technology, the term 'technology foresight' is often used as overall name for these methods. (Studies under the heading of scenario analysis and technology road mapping are also in many cases based on expert assessments.) In technology foresight a range of techniques for gathering and integrating expert assessments are used. These are for example expert panels, scenario meetings, brainstorm exercises and vision paper writing. For an introduction to technology foresight techniques see (Keenan, 2003). Often the methods make the experts articulate their expectations in another way than they are used to within their normal work, thereby to some extent overcoming the limitations implied by their specific subfield.

In addition to the expert opinions gathered through technology foresight studies and similar reports, direct contact with experts in the energy technology area can also be used as method approach for the analysis. The direct contact can take on the shape of for example interviews and scenario workshops. Through these approaches, assessments from selected individual experts or from small groups of experts can be obtained.

When addressing future costs in the long-term perspective, it will often be the case that only few experts specifically on cost issues can be found. Cost experts are of course very fine to include, however often the analysis must build on also other kinds of experts. The experts addressed shall be selected through the criteria: what are the most central expertise areas to include; how can the different expertise areas complement each other (it shall not just be one type of experts, e.g. not only engineers or only manufacturers of the energy technology). Moreover, a criterion for selecting the experts is their capability of and enthusiasm about participating in the discussion of the long-term future perspectives. Some experts find it very interesting to go into visionary discussions of the long-term aspects while other find it annoying.

Both in full technology foresight studies and in individual contact, interviews etc. it can be a problem that the cost dimension is an aspect that not all experts are used to talking about. They do not all equally well speak the 'cost language'. To some extent this might be evaded by preparing the experts with some of the existing knowledge about the costs.

Despite the unique insight and overview, expert assessments are still partial perspectives. This is the draw back of methods building on expert assessment; or the other side of the coin one might say. Experts will always try to promote their own area and perspective. Single statements of expert opinions or expert assessments can never stand alone as material for an analysis, but must be compared with many other statements and seen in context with other perspectives. This also implies that it is a requirement for making expert-based analyses that the analyst carrying out the analysis has experience with the energy technology area in case. If a newcomer tries to make such analysis there is a risk that the analysis will get character of naïve 'microphone holding'.

Analysis building on expert assessments and opinions can be used in combination with other analysis approaches e.g. experience curves etc. mentioned above, instead of being used as separate alternative, distinct from other approaches. In many cases an integrated approach will be most natural.

# 5. Cost development of energy technologies

In this chapter we present experience curves, and supplementary cost development analysis, for several new energy technologies; the technologies included are:

- Advanced fossil fuel technologies
- Advanced nuclear
- Fuel cells
- Wind turbines
- Photovoltaics (PV)
- Solar thermal power plants
- Biomass energy technologies
- Hydrogen technologies

The cost development study for each technology or technology group is divided into two or three of the different approaches described in chapter 2-4. First, cost development is presented based on the experience curve approach. Existing studies are presented and discussed and a progress ratio for each technology area is suggested. Second, a bottom-up assessment approach is used to describe the sources of cost reduction; historical sources of cost reduction as well as tentative future sources of cost reduction. This approach is used to complement the experience curve approach and to discuss divergence and consistency to the results and the progress ratio suggested using the experience curve approach. For some technologies, wind turbines and photovoltaics (PVs), long-term expert assessments have been applied.

## 5.1 Cost development of advance fossil fuel technologies

The main driver for fossil fuel and fossil-fuel technologies has been the demand for cheap, large scale electricity generation. In the future reduction of $CO_2$ and other environmental pollutants from fossil power plants will be the main drivers for fossil-fuel technology development. Lower $CO_2$ emissions per unit of power supply will be realized through advanced fossil-fuel technologies. The technologies to be named advanced fossil fuel technologies are many, covering all different types of coal, oil and natural gas technologies as well as technologies for $CO_2$ capture and sequestration.

In the NEEDS project several advanced fossil fuel technologies are being considered. However, the focus is on technologies fuelled by natural gas and coal, whereas less attention is put on oil fuelled technologies. The potential or candidate fossil technologies include:

Coal-fueled systems:

Pulverized Coal (PC) combustion power plants
Integrated Gasification Combined Cycle (IGCC) power plants
Hybrid gasification/combustion systems
Hybrid IGCC with fuel cells
Fluidized Bed Combustion (FBC) power plants
Co-firing biomass or wastes with coal
Combined Heat & Power (CHP) plants
Next Generation Power Plants – such as PC, HIPPS, PFBC, IGCC

Natural gas-fuelled systems:

Gas Combined Cycle (GCC) power plants

Gas Turbine (GT) power plants
Combined Heat & Power (CHP) plants
Oil-fuelled systems
Capture & Sequestration:
$CO_2$ Capture
Transportation of $CO_2$
Storing $CO_2$

The introduction and further diffusion of these technologies will depend on their cost development, and their cost development in comparison to other energy technologies. This chapter will give a brief introduction to a cost development analysis. However, the huge number of advanced fossil-fuel technologies can not be described in detail but the analysis will be of a more general character. In the text below, we apply the experience curve concept complemented with a bottom-up analysis of sources of cost reduction.

### 5.1.1 Cost development of advanced fossil fuel technologies – experience curves

Several experience curves have been developed for fossil-fuel technologies. Some studies present cost development for entire power plants; others have been limited to separate subsystems. In the following text we present the results of experience curves published and discuss the limitations of these and the cost development they imply.

A few experience curves describe the cost development of an entire power plant. Experience curves for coal power plants have been developed by Komanoff (1981) and Joskow and Rose (1985), however these are rather old and less relevant for the analysis of development of advance fossil fuel systems. The curves indicate that the cost for coal power plants in the 1970s increased rather than decreased– this due to additional cost of technologies to control pollutants such as particles, sulphur dioxide and nitrogen oxides.

Rubin et al. (2004a), Rubin et al. (2004b) and Riahi et al. (2004) present experience curves for sulphur dioxide and nitrogen oxide control technologies. The progress ratio for sulphur dioxide control technologies (FGD) is estimated to 87% in Riahi et al. (2004) and to 89% in Rubin et al. (2004b). The cost data in the studies reach from mid 1970s to mid 1990s. Rubin et al. (2004b) present an experience curve with a progress ratio of 88% for nitrogen oxide control technologies. The data for this experience curve reach from mid 1980 to 1995. Riahi et al. (2004) and Rubin et al. (2004b) suggest the use of a progress ratio of 90% to estimate future cost of carbon capture and storage systems for coal- and natural gas-based power plants.

MacGregor et al. (1991) present experience curves for GT and IGCC based on cost development from the 1970s. The experience curves indicate cost reduction as a function of cumulative installed capacity. However, no figure of the progress ratio is given in the paper. Claeson (2000)[3], analyse the development of specific investment prices of CCGT in the 1980s and 1990s. The study shows that the prices increased in the 1980s but reduced strongly in the 1990s. The experience curve based on the prices in the 1990s show a progress ratio of 75%. The authors, however, indicate that the development of prices may be the result of a pricing strategy (as illustrated in Chapter 2) and that further price reductions may be more limited.

[3] Cleason (2000) include and further analyse material published in Claeson (1999) and Claeson Colpier and Cornland (2002).

The authors suggest a progress ratio of 90% for the prediction of future cost. The authors also say that the specific investment cost and the use of different progress ratios have less impact on future electricity costs than the natural gas prices. Improvement in thermal efficiency is identified as an issue for great relevance for future cost reductions.

Moreover, an experience curve for CHPs (smaller than 1 $MW_{el}$) in Switzerland fueled by natural gas or diesel show a progress ratio of 61% for the timeframe of 1990-2001 (BFE, 2003). It is not clear if the reduction illustrated refers to actual costs changes or changes in market prices. According to the authors, the reduction has been heavily supported by policy intervention. However, no explanations have been given to what actually are the sources of the observed cost/price reductions. Although the data illustrate huge cost reductions for the time period, the extreme progress ratio ought to be considered with uncertainties.

Some publications present studies on future cost development based on “assumed” progress ratios. (No actual data has been collected and no experience curves have been developed). Kouvaritakis et al. (2000) present progress ratios for several fossil fuel systems.[4] The progress ratios “assumed” for fossil fuel plants range from 76% to 99%. The value of 76% refers to gas-fired combined cycle (CC) power plant and 99% to conventional coal.[5] Moreover, McDonald and Schrattenholzer refer to Zhao (1999) for unpublished data cost development of natural gas infrastructures; the progress ratio for gas pipelines onshore is referred to as 96.3% and the progress ratio for gas pipelines offshore is referred to as 76%. McDonald and Schrattenholzer also refer to Blackwood (1997) for unpublished data cost development of oil extraction indicating a progress ratio of approximately 75%.

*Comments*
In all, the number of studies on experience curves found in the literature is limited. The experience curves available do not give a full picture of cost development for fossil fuel systems.

The experience curves studies show that cost of coal power plants increased in the 1970s. However, the costs for these plants may have reduced ever since due to cost reductions such as those identified for sulphur dioxide and nitrogen oxide control technologies. The progress ratio for sulphur dioxide and nitrogen oxide control technologies has been estimated to approximately 90%. There are no experience curves studies differentiating different coal power technologies e.g. pulverised coal (PC) combustion power plants, integrated gasification combined cycle (IGCC) power plants, hybrid gasification/ combustion systems, fluidised bed combustion (FBC) power plants or combined heat & power (CHP) plants. For the NEEDS project we would like to suggest a progress ratio of 95% for all types of coal power plants. To underline the uncertainty we suggest a sensitivity analysis of applying an additional lower sensitivity value of 93% and an upper sensitivity value of 97%.

Experience curves on natural gas-fueled systems are also limited and the studies on CCGT indicate a progress ratio for the investment cost of CCGT of approximately 90%. For the NEEDS project we would like to suggest a progress ratio of 90% for all types of gas-fueled

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[4] There are no references to any data used for developing experience curves and it seems that the progress ratios are assumed (theoretical) rather than based on real data and experience curves actually developed.

[5] McDonald and Schrattenholzer refer to Zhao (1999) for unpublished data cost development of natural gas infrastructures. McDonald and Schrattenholzer also refer to Blackwood (1997) for unpublished data cost development of oil extraction.

technologies. To underline the uncertainty (and the possibilities of much larger cost reductions as indicated by the Swiss study) we suggest a sensitivity analysis of applying an additional lower sensitivity value of 85% and an upper sensitivity value of 95%.

There are no experience curve studies available on oil – fueled systems. Due to the limited development foreseen in this area we suggest a progress ratio of 100% in the NEEDS project. (The assumption may, however, be conservative for some systems like oil-fuelled GCC).

Additional to the cost development discussed above, the cost of $CO_2$ capture and storage (CCS) shall be assessed. Future cost of advanced fossil fuel power plants will initially increase due to the additional cost of CCS. This cost is, however, likely to decrease over time. In the NEEDS project we suggest for CCS the use of a progress ratio of 90%, as in the case of sulphur dioxide and nitrogen oxide control technologies. To underline the uncertainty we suggest a sensitivity analysis of applying an additional lower sensitivity value of 88% and an upper sensitivity value of 92%.

It is important to notice that the cost development studies above only cover the cost development of the technologies and do not cover the fuel cost. Considering cost of electricity based on fossil fuel the technology cost will be a partial source of cost reduction –important will also be the efficiency of the plant and the cost of fuel.

### 5.1.2 Cost development of advanced fossil-fuel technologies – bottom-up assessment

The use of experience curves to analyse future cost reductions of advanced fossil-fuel technologies give only aggregated results. In this chapter we will illustrate the actual sources of cost reduction using a bottom-up approach. The chapter contains data and characteristics of fossil fuelled power plants for electricity generation comprising technical and economic parameters. In this chapter we also highlight efficiency improvements, crucial for cost reduction of generated electricity. The cost numbers stated in the following chapter show future cost development by the time horizon of 2035. The analysis of future construction costs for fossil power plants ends 15 years before the time horizon 2050, which is the defined time border for the investigation of electricity generation in NEEDS. This is due to the fact that for a power plant with construction begin later than 2035 a reasonable power plant operation phase is not possible. Between begin of construction and the commissioning of a coal fired power plant there is a time span of three to five years. The remaining ten years up to the time horizon of 2050 can be used for electricity generation and constitute the operation phase. Thus it is necessary to make distinction between the time horizon for fuel chain considerations, which reasonable reaches up to 2050 and the time horizon for construction of fossil fuelled power plants, which ends in 2035.[6]

The bottom-up assessment below refers to cost and efficiency figures described in the literature and cost and efficiency figures presented as balanced assumptions by the authors of this report from the Institut für Energiewirtschaft und Rationelle Energieanwendung (IER), Germany.

[6] The cost data reported in the following paragraphs is € referred to the year 2005.

*Steam power plants - Hard coal condensing steam power plant*
The efficiency of power plants using conventional high-temperature carbon steel alloys is restricted to values below 45 %. Only at advantageous north-European cooling conditions (e.g. Denmark, sea water cooling, and condenser pressure 35mbar) efficiencies of 45% are reached. Siemens Power Generation states 44.5% as maximum efficiency for such hard coal power plants (VARIO PLANT concept) (Segal and Alf, 2000).

Hard coal power plants with high efficiencies ≥ 45 % and power ratings > 300MW require raising the live steam conditions on values exceeding 270 bar/580 °C. Those steam conditions can be realized using ferritic-martensic materials (T 92, P 92, E 911 etc.), which facilitate to generate live steam at high super-critical pressures and temperatures without austenitic materials. However they are four times more costly than conventional ferritic alloys. These ferritic-martensic materials, have recently been developed in Japan (EPDC), in USA (EPRI) and within the EU (COST - program) for the application in power plants.

In Denmark such a hard coal power plant with 47% full load efficiency is run (Kjaer et al. 1998). From this power plant and from German projects for high-efficient hard coal power plants (for instance project in Westfalen (Germany) featuring net power of 325 MW, live steam condition of 290 bar/600 °C, temperature at reheater outlet of 620 °C and an full load efficiency of 47.35 %) cost information is available (Stapper, 1997).

In the German research project "KOMET 650" high-temperature materials for live steam conditions up to 300 bar/650 °C have been tested (BMWi, 1999). This will allow reaching efficiencies up to 48%. The EC funded research program, Advanced (700 °C) PF Power Plant" puts super alloys on a Ni-basis on the test in hard coal power plants with steam conditions of 375 bar/700 °C (Ultra Super Critical Steam, USC). Alloys on Ni-basis (super alloys) are more expensive then the ferritic-martensic materials P 92, T 92, E 911 etc., so that higher specific investment costs have to be anticipated (but not necessarily higher electricity generation costs). After a successful testing the project planning outlines the construction of a hard coal power plant with efficiencies in the range of 52 to 54% within the next decade (Kjaer, 2000). This efficiency range is a result of different assumptions for cooling conditions.

Other measures for efficiency enhancement are intermediate superheating, regenerative feed water preheating and the application of super-critical live steam pressures. Currently used hard coal condensing steam power plants normally feature on intermediate superheating and up to ten feed water preheating stages.

In order to reach high overall efficiencies (component efficiencies, power plant efficiency) also the losses outside of the cycle process have to be minimised (e.g. combustion and flue gas losses). Measures for utilizing the flue gas enthalpy are air preheating, cold end optimisation and flue gas release through a wet cooling tower.

In modern power plants all these measures for efficiency enhancement are applied. Under the assumption that the efficiency of power plant processes, components and boiler as they are applied in the ultra-supercritical power plant AD 700 of the „Advanced (700 °C) PF Power Plant"-EU-project can't be substantially improved, there is only an increase in the live steam temperature left for efficiency improvement. A temperature increase from 700°C to 800°C will improve the overall efficiency by 2.8 percent points. With this rough estimation starting from current condition, the highest efficiency attainable and thus the top end for efficiency improvements for hard coal condensing steam power plants is 55%.
Summarizing it can be stated:

- By the time horizon 2015 new hard coal power plants with efficiencies of 46-48% can be realized.
- In the period between 2015 and 2025 hard coal condensing steam power plants with efficiencies around 50% (maybe by 52%) can be built.
- Between 2025 and 2035 it is assumed that new hard coal steam condensing power plants are able to reach efficiencies higher 52%.

The specific power plant costs shown in Table 5.1 are estimated with the assumption that electricity generation costs of ultra-supercritical (USC) power plants do not exceed electricity generation costs of at this time sold ‘economic’ power plants (additional investment ≤reduction in fuel costs). This approach is supported by publications and presentations given for instance at the International Congress ‘Zukunft Kohle’ (Zukunft Kohle, 2001).

Table 5.1 shows technical and economic data for three power classes of hard coal power plants for the time horizons 2005, 2015 and 2025. As nowadays power plant producers offer hard coal power plants, which already at power regions around 300MW show similar steam parameters and efficiencies as large-scale power plants, but feature different cost degression by economy of scale, a distinction in different power classes was considered reasonable.

Table 5.1. Data on modern and future hard coal condensing steam power plants - (Data developed by Institut für Energiewirtschaft und Rationelle Energieanwendung (IER), Germany, author of chapter 5.1.2)

| | Unit | 2005 | | | 2015 | | | 2025 | | | 2035 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Electrical net power $P_{el,\,max}$ | $MW_{el}$ | 350 | 600 | 800 | 350 | 600 | 800 | 350 | 600 | 800 | 350 | 600 | 800 |
| $\eta_{net}$ | % | 46 | 46 | 46 | 47 | 47 | 47 | 50 | 50 | 50 | 52 | 52 | 52 |
| Technical life time | year | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| Spec. investment cost | €/$kW_{el}$ | 1060 | 920 | 820 | 1000 | 900 | 850 | 995 | 895 | 845 | 995 | 895 | 845 |
| Construction interest | %-invest | 8,2 | 8,2 | 8,2 | 8,2 | 8,2 | 8,2 | 8,2 | 8,2 | 8,2 | 8,2 | 8,2 | 8,2 |
| Dismantling costs | €/$kW_{el}$ | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Fixed operational costs | €/$kW_{el}$ | 50 | 41 | 35 | 50 | 41 | 35 | 50 | 41 | 35 | 50 | 41 | 35 |
| Variable operational costs | €/$MWh_{el}$ | 2,6 | 2,6 | 2,6 | 2,6 | 2,6 | 2,6 | 2,6 | 2,6 | 2,6 | 2,6 | 2,6 | 2,6 |

*Steam power plants - Lignite condensing steam power plant*

Lignite power plants with super-critical steam conditions are installed exclusively in Germany. In other countries using lignite only power plants with subcritical parameters are operated. Cost data on current lignite condensing steam power plants stem from personal communication with Siemens, ALSTOM and RWE Rheinbraun. The newest lignite power plant so far, commissioned in Niederaußem in autumn 2002 applies state-of-the-art BoA technology (lignite plants with optimised systems engineering)[7] and shows a gross power of 1012 MW, net power of 965 MW, live steam conditions of 275 bar/580 °C, intermediate superheating 59 bar/600 °C, a ten-staged regenerative feed water preheating, a condenser pressure (two-staged) 28/34 mbar and an efficiency beyond 43% (Kallmeyer et al. 1999, RWE 2004). The specific investment costs account for 1180 €/kW. The power industry (Rheinbraun AG) plans further reduction of specific investment costs for BoA power plants up to 920 €/kW in 2010.

[7] Braunkohleblock mit optimierter Anlagentechnik. “Engineers have scored efficiency gains at many points in the power plant process by using high-tech materials and computer-modelled turbine blades, for example, and by recycling residual heat and reducing auxiliary power requirements.” (http://www.rwe.com/generator.aspx/rwe-power-icw/power-plant-renewal-programme/boa-2-3/vorhaben-boa-2-3/language=en/id=331502/boa-2-3-page.html)

Further efficiency improvement could be reached by integrating recent coal drying technology within the system engineering of the lignite power plants (BoA+) (Kallmeyer et al. 1999). This would allow efficiencies up to 50%. From technical point of view power plants using BoA+ technology are anticipated to be built past 2015. However market penetration of the BoA+ technology depends on its costs, which will be higher compared to the BoA technology, which is currently in use.

Summarizing it can be stated:

- By 2015 lignite condensing steam power plants with specific investment costs of 1180€/kW and efficiencies around 45% can be realized.
- Between 2015 and 2025 it will be possible to reduce the specific investment costs to 920€/kW. Efficiencies up to 50% are possible using BoA+-technology, but market penetration of this technology is not sure.
- With further technological development the BoA+-technology and efficiencies around 50% are reachable between 2025 and 2035. However the new technology BoA+ is much more complex than BoA. Thus according to the approach used for ultra super-critical (USC) hard coal power plants, it has been estimated that the increase in investment costs never exceeds the savings in fuel costs (investment cost increase ≤ fuel costs saving).

Currently in the field of lignite power plants there is no major demand for power plants with lower power ranges as it was the case for hard coal power plants. Therefore only the high power class was considered as reference technology for lignite power plants. Technical and economic data of representative lignite condensing steam power plant is shown for different time horizons in Table 5.2.

Table 5.2. Data on modern and future lignite condensing steam power plants. (Data developed by Institut für Energiewirtschaft und Rationelle Energieanwendung (IER), Germany, author of chapter 5.1.2).

| | Unit | 2005 | 2015 | 2025 | 2035 |
|---|---|---|---|---|---|
| Electrical net power $P_{el, max}$ | $MW_{el}$ | 1050 | 1050 | 1050 | 1050 |
| $\eta_{net}$ | % | 45 | 45 | 50[8] | 50 |
| Technical life time | year | 35 | 35 | 35 | 35 |
| Spec. investment cost | €/$kW_{el}$ | 1200 | 900 | 900 | 900 |
| Construction interest | %-Invest | 8,2 | 8,2 | 8,2 | 8,2 |
| Dismantling costs | €/$kW_{el}$ | 30 | 30 | 30 | 30 |
| Fixed operational costs | €/$kW_{el}$ | 33 | 33 | 33 | 33 |
| Variable operational costs | €/$MWh_{el}$ | 1 | 1 | 1 | 1 |

*Natural gas combined cycle (GCC) power plant*

GCC power plants feature the best efficiency of all thermal based electricity generation technologies applied at present. This efficiency is mainly determined by the efficiency of the gas turbine turbo set (gas turbine + compressor). The gas turbine accounts for about two thirds of the capacity of the GCC, the remaining third is supplied by the steam turbine. The efficiency of the gas turbine is basically depending on the gas turbine inlet temperature and the pressure ratio.

[8] Assumed is an more efficient lignite drying, which is in line with efficiency augments, but also with increased costs

Power plant producers of heavy duty gas turbines state an efficiency of 57.5% for current natural gas fired steam and gas power plants. The 60 percent barrier is to be reached in about six years. The specific investment is anticipated to further decline as gas turbines with higher capacity are expected to penetrate the market. The breakeven capacity allowing further cost degression is not achieved yet. The technical development aims at the construction of gas turbines with a capacity of 500 MW. However cost information on such future gas turbines are not available from power plant producers.

As the specific investment costs of GCC units are approximately half of those of hard coal power plants, the fuel costs have considerable influence on their cost effectiveness.

Summarizing it can be stated:

- Between 2015 and 2025 it is anticipated that natural gas combined cycle power plants with capacities around 500MW and efficiencies of 60% will be offered at the world market.
- For 2025 to 2035 further efficiency enhancement for the same capacity level is assumed. This implies gas turbines with higher inlet temperatures (>1230 °C with higher compressor pressure ratio) and advanced vane materials as well as enhanced vane cooling.
- In the long run of future development the efficiency of natural gas combined cycle power plants will not exceed the 65% barrier, even if gas turbines with intermediate heating and measures for component characteristics enhancement are assumed.

Table 5.3 shows data for natural gas combined cycle power plants. The life time of 35 years is reached under the assumption that highly stressed components of the turbines with lower life time are revised or replaced in due time during operation.

Table 5.3. Data on modern and future natural gas combined cycle power plants. (Data developed by Institut für Energiewirtschaft und Rationelle Energieanwendung (IER), Germany, author of chapter 5.1.2).

| | Unit | 2005 | | 2015 | | 2025 | | 2035 | |
|---|---|---|---|---|---|---|---|---|---|
| Electrical net power $P_{el,\,max}$ | $MW_{el}$ | 400 | 800 | 420 | 1000 | 500 | 1000 | 500 | 1000 |
| $\eta_{netto}$ | % | 57,5 | 57,5 | 59 | 60 | 62 | 62 | 63 | 63 |
| Technical life time | year | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| Spec. investment cost | €/$kW_{el}$ | 440 | 440 | 440 | 440 | 425 | 385 | 425 | 385 |
| Construction interest | %-Invest | 5,4 | 5,4 | 5,4 | 5,4 | 5,4 | 5,4 | 5,4 | 5,4 |
| Dismantling costs | €/$kW_{el}$ | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| Fixed operational costs | €/$kW_{el}$ | 23 | 19 | 20 | 18 | 20 | 18 | 20 | 18 |
| Variable operational costs | €/$MWh_{el}$ | 1,5 | 1,5 | 1,5 | 1,5 | 1,5 | 1,5 | 1,5 | 1,5 |

*Hard coal power plant with gas combined cycle turbines – IGCC power plant*

As discussed above, efficiencies higher than 55% are hardly feasible for a conventional hard coal steam power plants, even if applying Ni-based alloys. Thus other hard coal conversion technologies featuring higher efficiencies (and better environmental performance, e.g. drastically reduced SOx emissions compared to pulverized combustion) have been researched. The combination of gas-fired gas turbines with downstream steam turbine as in GCC turned out to be a relatively cheap and promising solution. However, as gas turbines can not be charged with uncleaned flue gas from coal combustion, the coal has to be gasified before combustion. This is the concept of IGCC power plants, which can be constructed using components and materials already technically proven and available in the market. Depending on the development of gas turbines, hard coal IGCC power plants can potentially feature higher efficiencies than hard coal steam power plants. When GCC efficiencies will achieve 63% in future, hard coal IGCC power plants could reach an efficiency of 56%, some time afterwards (Kloster, 1998).

Summarizing it can be stated:

- By 2015 IGCC power plants could still be seen as demonstration plants or ‘First-of-its-kind’. The currently operational most advanced European IGCC power plants (Buggenum, Puertollano) are neither representative in terms of costs nor in terms of efficiency. They had no commercial financing. Furthermore, they feature gas turbines that are not state of the art anymore, and are already technologically outdated.
- From 2015 to 2025 the technical data of the representative IGCC power plant stem from an IGCC optimisation in the EU funded study Advanced Cycles Technologies (1998). Such a power plant could be built with currently available and proven material, components and gas cleaning procedures. The efficiency of this power plant was calculated as 51,5% and can be achieved with gas turbine improvements, which is expected by 2015. Specific investment costs of 860 €/kW were estimated.
- Between 2025 and 2035 the efficiency of 55% is calculated according to the expected efficiency development of GCC of 63 %. The efficiency reduction of 8% depends on exergy losses during gasification and gas cleaning. Future progress in gasification and gas cleaning will further reduce the efficiency difference between IGCC and GCC.

Table 5.4. Data on future hard coal IGCC power plants. (Data developed by Institut für Energiewirtschaft und Rationelle Energieanwendung (IER), Germany, author of chapter 5.1.2).

| | Unit | 2005 | 2015 | 2025 | 2035 |
|---|---|---|---|---|---|
| Electrical net power $P_{el, max}$ | $MW_{el}$ | - | 450 | 450 | 450 |
| $\eta_{net}$ | % | - | 51 | 54 | 55 |
| Technical life time | year | - | 35 | 35 | 35 |
| Spec. investment cost | €/$kW_{el}$ | - | 1200 | 1100 | 1100 |
| Construction interest | %-Invest | - | 8,2 | 8,2 | 8,2 |
| Dismantling costs | €/$kW_{el}$ | - | 50 | 50 | 50 |
| Fixed operational costs | €/$kW_{el}$ | - | 53 | 53 | 53 |
| Variable operational costs | €/$MWh_{el}$ | - | 3,1 | 3,1 | 3,1 |

### *Hard coal IGCC power plant with $CO_2$ capture*

The basic engineering for a hard coal IGCC power plant with $CO_2$ capture has been investigated in an EC funded study (Pruschek et al. 1997), where costs of power plant components for $CO_2$ capture (including compression) were estimated (e.g., shift reactor, absorber, regeneration)[9]. Furthermore, the consumption of adsorption liquid and the energy demand for $CO_2$ capture were analysed. $CO_2$ capture should lead to an efficiency reduction of about six percent points compared to an IGCC power plant without $CO_2$ capture (Pruschek et al. 1997; Pruschek et al. 1998). Table 5.5 shows data on IGCC power plants with $CO_2$ capture obtained from engineering studies on IGCC $CO_2$ capture using rectisol scrubbing for $CO_2$ separation.

[9] Cost data o carbon dioxide capture and storage is also presented in IPCC (1992).

Summarizing it can be stated:

- In the time span until 2015 there is no representative hard coal IGCC power plant with $CO_2$ capture considered as there is no market introduction of IGCC, but only demonstration plants, which are without $CO_2$ capture.
- Between 2015 and 2025 as well as between 2025 and 2035 the costs and efficiency of the hard coal IGCC with $CO_2$ capture are derived from hard coal IGCC without $CO_2$ capture.
- The data are calculated for a $CO_2$ capture rate of 90% ($CO_2$ emission reduction of approximately 88%).

Table 5.5. Data on future hard coal IGCC power plants with $CO_2$ capture. (Data developed by Institut für Energiewirtschaft und Rationelle Energieanwendung (IER), Germany, author of chapter 5.1.2).

| | unit | 2005 | 2015 | 2025 | 2035 |
|---|---|---|---|---|---|
| Electrical net power $P_{el, max}$ | $MW_{el}$ | - | 425 | 425 | 425 |
| $\eta_{net}$ | % | - | 45 | 48 | 49 |
| Technical life time | year | - | 35 | 35 | 35 |
| Spec. investment cost | €/$kW_{el}$ | - | 1370 | 1370 | 1370 |
| Construction interest | %-Invest | - | 8,2 | 8,2 | 8,2 |
| Dismantling costs | €/$kW_{el}$ | - | 55 | 55 | 55 |
| Fixed operational costs | €/$kW_{el}$ | - | 65 | 65 | 65 |
| Variable operational costs | €/$MWh_{el}$ | - | 3,6 | 3,6 | 3,6 |

The $CO_2$ abatement costs account for 30 to 40 €/t $CO_2$. Liquefaction and pipeline transportation cause further expenses (Göttlicher, 1999). Altogether the $CO_2$ abatement costs per ton of liquefied $CO_2$ transported in pipeline over 1000km are calculated to approximately 50€. This calculation is based on costs of existing technologies.

### 5.1.3 Cost development of advanced fossil-fuel technologies – summary

Experience curves for advance fossil fuel technologies are limited. Those available, some of them old, some of them generic, show minor cost reductions for coal-fuelled power plants. Experience curves for gas-fuelled technologies illustrate somewhat larger cost reductions. The complementing bottom-up analysis indicate incremental cost reductions for hard coal condensing steam power plant, lignite condensing steam power plant, natural gas combined cycle (GCC) power plant and hard coal power plants with gas combined cycle turbines (IGCC) According to such analysis, technology improvers and learning are such that booth cost reductions and improvements of plant efficiency will occur.

In the bottom-up assessment the hard coal IGCC power plants with $CO_2$ capture are seen as demonstration projects and cost reduction is not seen as likely within the analysed time frame. The experience curve estimates, however, open up for future cost reductions.

In the NEEDS project we suggest a progress ratio of 95% for all types of coal power plants. To underline the uncertainty we suggest a sensitivity analysis of applying an additional lower sensitivity value of 93% and an upper sensitivity value of 97%. For all types of gas-fueled technologies we suggest a progress ratio of 90%. To underline the uncertainty we suggest a sensitivity analysis of applying an additional lower sensitivity value of 85% and an upper sensitivity value of 95%. In the case of $CO_2$ capture and sequestration we do not find support for the cost reductions anticipated in experience curves studies and therefore suggest the use of a 100% progress ratio.

## 5.2 Cost development of advanced nuclear

The first generation of nuclear reactors was developed in the 1950s and the 1960s. In the 1970s reactors of the second generation of commercial power plants were installed. These were followed by a third generation of reactors in the 1990s that offered advances in safety and economics, see Figure 14.1. At present, 439 reactors, for 361 $GW_e$ total capacity installed worldwide, are in commercial operation (Garzenne et al., 2005).

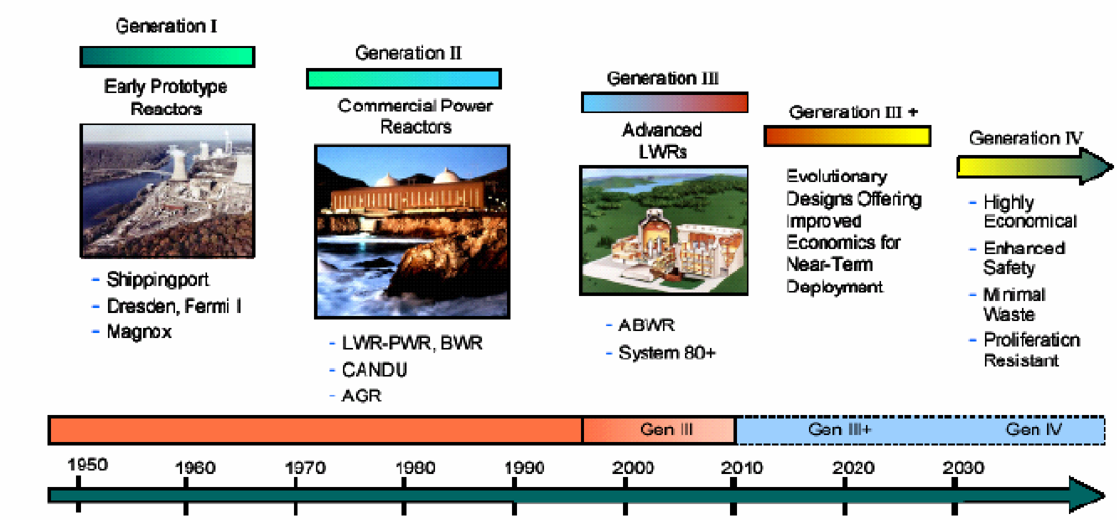


Figure 5.1. Nuclear reactors over time (U.S DOE, 2002).

The types of reactors installed today are many. The most common is the light water reactors (LWRs) which contribute to more than 88 % of the nuclear electrical power; three quarters of LWRs are pressurized water reactors (PWR), one quarter boiling water reactors (BWR). Other types are gas-cooled reactors, pressurized heavy-water reactors, light water graphite reactors and fast-breeder reactors prototypes (see Garzenne et al., 2005).

New types of reactors are being developed. Advancements of generation three, i.e. evolutionary technologies based on existing reactor designs, include features aiming for example at improved safety, longer reactor life span, reduction of highly radioactive waste, improved performance, and cost reductions. Moreover, a fourth generation of reactors based on innovative concepts is expected to become operational in a few decades from now (Figure 5.1).

The new reactors have been profiled as highly economical, and costs are estimated be lower than for older reactors. In order to assess the competitiveness of nuclear power, it will be of interest to analyse how much and how fast costs can be reduced. In this chapter we apply the experience curve concept to estimate the size of future cost development. The experience curve concept is also complemented with a bottom-up analysis describing the different sources of cost reduction.

### 5.2.1 Cost development of advanced nuclear – experience curves

The number of studies on experience curves for nuclear power found in the literature is limited. The experience curves studies available, show that cost of nuclear plants increased in the 1970s. The study by Komanoff (1981), based on nuclear plants in the US, say that *"over the course of the 1970s, the changes approximately doubled the amounts of material, equipment, and labour and tripled the design engineering effort required per unit of nuclear capacity"*. The study by Cantor and Hewlett, (1988) show that the construction cost increased. New unpublished material from IIASA, based on investment cost of nuclear in France 1977-2000 (EDF CdR Projections, PEON/DIGEC), show that the projected investment costs per kW have continued to increase over time, see figure 14.2 (Grübler , 2005).

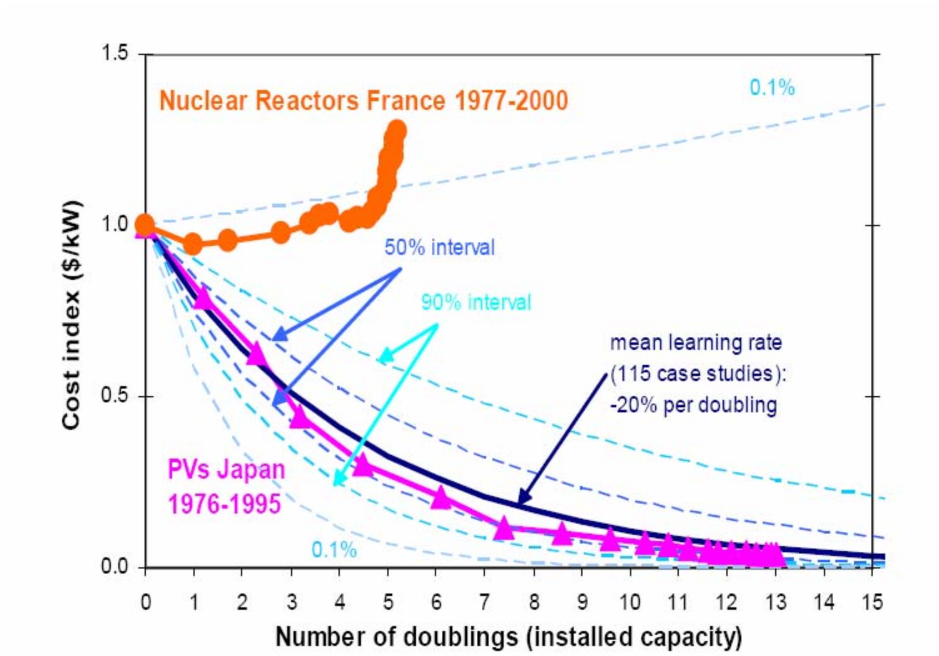


Figure 5.2. Cost development as a function of number of doublings in installed capacity for nuclear reactors in France 1977-2000 and Photovoltaics (PVs) in Japan 1976-1995 (Grübler, 2005)

Other publications also discuss cost development of nuclear (see for example Mooz,1979; Mooz, 1981; Zimmerman, 1982). Kouvaritakis et al. (2000) present an experience curve and a progress ratios for conventional nuclear and new nuclear, however, there are no references to the data used for developing experience curves. It is not clear if experience curves actually have been developed. The progress ratios "assumed" for conventional nuclear and new nuclear is 94.2%. This progress ratio is also presented in McDonald and Schrattenholzer (2001). IAEA (2003) assume progress ratios of 96%, 97% and 100% in their scenarios.

Experience curves studies, in more general terms, have shown that there is a difference between different types of technologies, see chapter 1. Module technologies for which cost reduction often will be a result of economies of scale in terms of mass-production and larger production plants show progress ratios from 70% to 95%. Plants, such as nuclear power plants, on the other hand, show more limiting progress ratios ranging from 82% to more than 100% (representing cost increase) (Neij, 1999).

Several explanations have been given for the limited cost reductions related to experience in the case of nuclear. Nuclear plants needs in some cases to be individually designed and build according to local conditions which limit the possibilities of cost reduction due to experience effects. Standardised plants have however, been developed in France. The technology relates to long lead times due to long planning, construction and commissioning periods, thus the experience from one project will lead to limited cost reductions in the next project. Technology changes also need safety licenses, which even further slow down the process of change. Learning and experience sharing has been limited internationally due to security and proprietary considerations.

In all, the experience curves show limited cost reductions over the years - this due to regulatory effects that have resulted in cost increase rather than reductions, few reactors being build in recent years limiting the number of learning opportunities, limitations in cost reduction due to scale effect, etc. According to the curve, shown above, the investment cost per kW has even increased considerably over the years. The extrapolation of the nuclear experience curve does not indicate any cost reductions for the future. Moreover, the nuclear power technology is relatively mature, and according to the experience curves any cost reductions as a result of experience will rely on massive introduction of new plants. Altogether, the experience curve available, and the extrapolation of this, does not support assumptions on any cost reductions, but rather cost stabilisation of increase. The cost increase will then be due to higher safety and environmental requirements.

### 5.2.2 Cost development of advanced nuclear – bottom-up assessments

The use of experience curves to analyse future cost reductions of nuclear has been criticized; the experience curves are criticised for not taking into account new generations of technologies and radical changes. PIU (2002) states that although the experience curve indicate smaller or no cost reductions in these issues, they do not prove that overall cost reduction in nuclear in the future must be small. PIU stresses the importance of using engineering judgement to estimate future cost reductions of nuclear.

On the other hand, there are other stakeholders claiming that the nuclear industry is over-optimistic in their engineering judgement of estimated future cost (see for example NEF, 2005). The critique is related to limitations in cost reductions due to limitations in standardisations, scale effects and learning effects.

*Technology development*
The industry presents several improvements of new reactors. The improvements may either be incremental and rely on smaller improvements in already existing third generation reactors or be more radical improvements or innovative designs related to an introduction of a new and fourth generation of nuclear reactors. The incremental improvements often referred to are (see Garzenne et al., 2005):

- Improved safety, particularly by implementing passive safety features and simplification of the design.
- Reduction of highly radioactive waste and improvement of waste management.
- Smaller amounts of expensive materials to be used in power plants.
- Less construction will take place on site and more construction will be in factories which will reduce costs.

Some incremental improvements relate directly to cost reductions, such as

- Lower generation costs, with enhanced fuel performances (higher burn up, longer operating cycle, recycling of plutonium).
- Optimisation of the fuel cycle (for instance, for uranium enrichment, replacement of gaseous diffusion by gas centrifuge which is 50 to 60 times less energy intensive.
- More cost effective industrial reprocessing (by optimising the existing PUREX technology).
- Longer reactor life span; this was initially 30 years for Generation II PWR, could most likely be extended to 50-60 years for numerous existing reactors, and directly be aimed at 60 years for Generation III & III+ systems.
- International competitiveness and more effective procurement procedures will give lower cost

Garzenne et al. (2005) give an example of such a future third generation reactor, the European Pressurized Reactor (EPR) developed by Framatome and Siemens, which have merged into Framatome ANP (AREVA). The advantages of the EPR are:

- Important gains in performance including availability over 90% and lower operating costs, translating into greater cost-competitiveness.
- Significant safety improvements: the probability of a core meltdown, already extremely low with the PWR, should be even lower with the EPR. But if such an event were nevertheless to occur, there should be no significant impact outside the power plant due to the extremely robust containment building surrounding the reactor.
- An answer to sustainable development concerns: by design, the EPR generates more electricity from a given quantity of fuel, thus conserving uranium resources (-15%) and generating less waste (-15%) compared to older PWRs, current fuel design, and core management practice.

Another reactor is the High Temperature Reactors (HTR) (known as TRISO Particle). The advantage of this reactor would be the possibility to generated high temperature heat for new purposes.

The introduction of a fourth generation of reactors represents a technical breakthrough, with technological changes affecting the reactors and also the entire fuel cycle. For example, the FBR would allow a better use of uranium and increase the amount of energy produced from a mass unit of virgin uranium by a factor of 50 to 100 if compared to thermal reactors of Generation II & III. The different types of FBR differ by the fuel (plutonium, uranium and thorium) and the cooling material (helium gas, sodium and lead-bismuth). Moreover, in the FBRs, plutonium is entirely recycled, reducing the accumulation of highly radioactive waste in the form of spent nuclear fuel.

*Cost reduction*

A problem analyzing cost of nuclear is that cost data is hard to find. Moreover, it is not always clear how the figures available have been estimated, i.e. what interest rates have been used etc. Some cost figures have been presented, however, it is not always clear whether these are target costs or cost based on advanced engineering judgement.

The average cost of nuclear electricity of today has been estimated by OECD (2005) to approximately 2.9 €c/kWh. However, the cost very much depends on the interest rates, amortization time and service life. OECD (2005) has estimated the range of cost of nuclear electricity to 1.6-2.4 €c/kWh (21-31 USD/MWh) using a discount rate of 5% and 2.3-3.9 €c/kWh (30-50 USD/MWh) using a discount rate of 10%.

Important sources of cost reduction in the past have been the reduction of O&M costs (Stricker and Leclercq, 2004, in Lecarpentier and Beslin, 2006), the reduction in construction time (Bertel and Naudet, 2004, in Lecarpentier and Beslin, 2006) and the increase availability factor (Stricker and Leclercq, 2004, in Lecarpentier and Beslin, 2006). In all the cost is no longer increasing but have stabilized, see Figure 5.3 One important reason for the increasing investment costs has been the continuously improved safety.

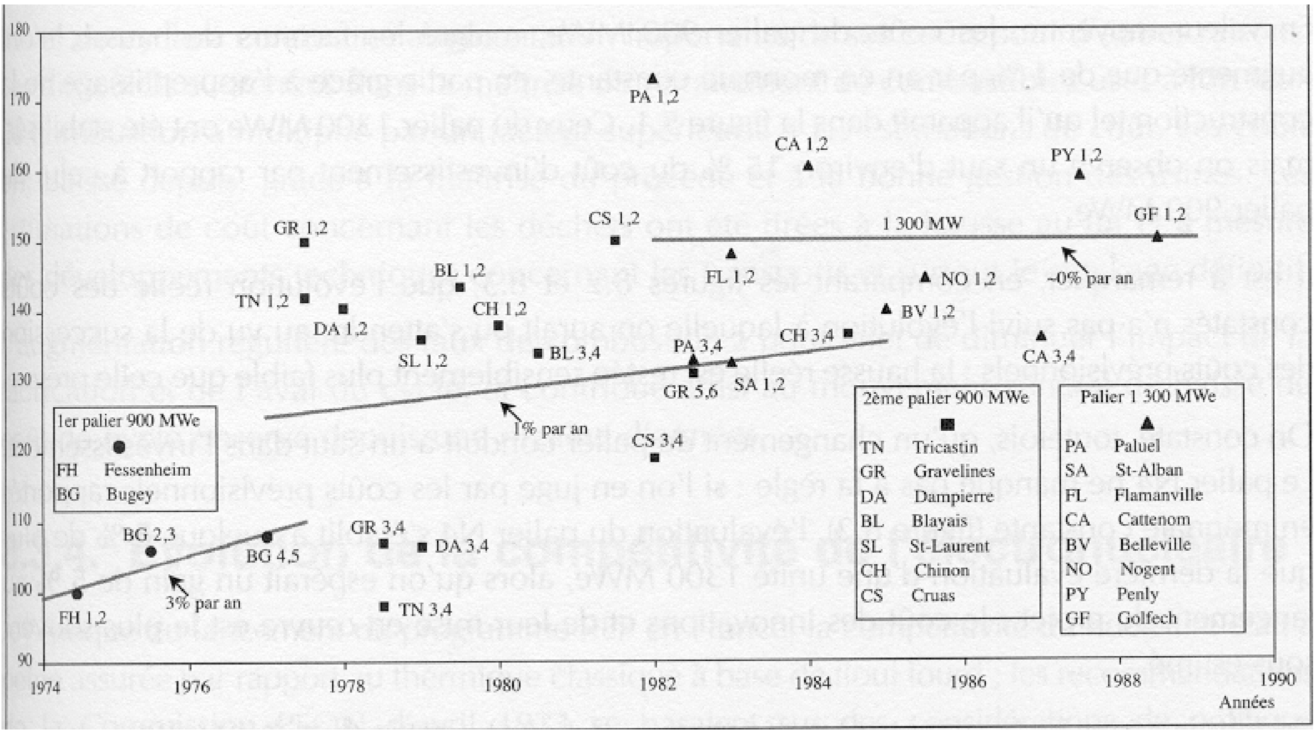


Figure 5.3. Evolution of the investment costs in France (base 100 in 1974, by Fessenheim in Lecarpentier D. and Beslin G, 2006).

Dones after Hirschberg et al. (2005) presents estimations of future generation costs, see Table 5.6. The estimations of costs is based on detailed calculations, actual orders (FOAK EPR, Finland), or on already operational units (ABWR, Japan). In the case of Japan, large part of the higher costs is explained by the expenditures for earthquake protection. The low cost of the Finnish reactor can be explained with four elements: a) the offer for the turn-key plant was relatively inexpensive; b) the Finnish government is securing favourable financial conditions; c) fuel costs are very low, which most probably is due to very low costs for on-site waste disposal; and, d) already signed long-term contracts with the paper industry. The generation cost of a similar reactor in France will probably be more expensive due to somewhat higher interest rates. The same will be if the EPR was built in Switzerland, but here the fuel costs should be even higher for the higher waste disposal costs. The total generation costs are thus estimated to 2.6-3.2 €c/kWh (Hardegger and Foskolos, 2005; Hirschberg et al., 2005). Data available for Generation IV technologies are mostly goal values or first rough estimation, which would allow nuclear to be competitive (GIF, 2002).

Table 5.6. Cost of nuclear reactors, existing and planned (Dones after Hirschberg et al., 2005). Not all cost data include capital cost but only operational cost.

| Cost [€c/kWh] | Today | Future | Source/Remarks |
|---|---|---|---|
| CH | 2.6-3.4 | | Interval for current Swiss plants |
| | 3.9 | 3.4 | (Prognos 1999) |
| Germany Konvoi Type | 2.9 | 1.5 | (UIC 2004) (1.5 after full amortization) |
| OECD | 2.9 | 2.1-2.8 | (UIC 2004; OECD/IEA 1992) |
| Japan | 5.8 | 4.8 | ABWR (First unit). (UIC 2004; OECD/IEA 1998) |
| France | 3.2 | 2.7 | (UIC 2004; OECD/IEA 1998) |
| UK | 3.4 | - | (RAE 2004; UIC 2004; OECD/IEA 1998) |
| USA Production | 1.4 | - | (NEI 2004) |
| USA DOE (55% Capital) | 3.2 | 2.8 | (NEI 2004; UIC 2004) |
| USA New Plants FOAKE | - | 3.9-5.8 | First of a Kind costs (Tolley & Jones 2004) |
| USA New Plants Series | - | 2.6-3.9 | Cost Series (Tolley & Jones 2004) |
| EPR Finland (Today: BWR) | 1.8 | 2.4 | (Tarjanne & Loustarinen 2002) |
| EPR France | - | 2.3-2.6 | (DGEMP 2003) |
| EPR CH | - | 2.6-3.4 | Higher costs for waste disposal |
| GEN IV | - | 1.6-2.3 | (GIF 2002) |

Garzenne et al. (2005) assume a target cost of nuclear in 2050 of approximately 2.7-3.0 €c/kWh; based on a fix cost of 2.3-2.6 €c/kWh and a variable cost of 0.4 €c/kWh. Most estimates describe future cost in the same range as cost of today, or slightly lower. A crucial point seems to be interest rates and waste disposal costs.

### 5.2.3 Cost development of advanced nuclear – summary

The experience curve for nuclear illustrate a cost development path that indicates increase in costs rather than reduction in costs. However, the bottom-up studies indicate several important areas of future technology development and cost development have been presented based on these technology development paths. These cost estimates, in general describe future cost in the same range as cost of today, however, some estimates are much higher and others much lower. The cost target on the fourth generation reactors describe notably lower costs.

In the NEEDS project we suggest an experience curve with a progress ratio of 100%. This indicates cost stabilisation and a break in the trend of cost increase as indicated by the historical cost development data. To underline the uncertainty of the cost reduction we suggest sensitivity analysis applying an additional lower sensitivity value of 95% and an upper sensitivity value of 105%. The suggested figure does not take into account the introduction of Gen IV power plants.

The bottom-up studies support the use of a progress ratio of 100% or slightly less, assuming a lower cost of waste disposal. More radical cost reductions may be due to the introduction of fourth generation reactors. Here it has been assumed that the introduction of the fourth generation reactors is likely to appear in Europe no earlier than 2040.

## 5.3 Cost development of fuel cells

Fuel cells have been developed to be used as automotive and stationary systems. In this project we only include stationary systems. The technology concepts considered are:

- Polymer Electrolyte Membrane Fuel Cells (PEMFC)
- Phosphoric Acid Fuel Cell (PAFC)
- Solid Oxide Fuel Cell (SOFC)
- Molten Carbonate Fuel Cell (MCFC)

The size and the commercial applications of these different technologies will differ. The PEMFC of 1-10kW as well as the SOFC in the same range will most likely be used in the residential and commercial sectors; the PEMFC of 200 kW, the SOFC and MCFC of 200 kW-1 MW will be used in the commercial and small industrial sectors as well as for district heating.

The only commercialized fuel cell as far is the Phosphoric Acid Fuel Cell (PAFC), which has been used in niche industries. The production of this fuel cell has stopped and the fuel cell has been replaced by the PEMFC, which have approximately the same performance and cost as the PEMFC.

As far, the experience of the fuel cells is limited and the cost is high. To commercialize the fuel cell the costs need to be reduced. The question is how much and how fast costs can be reduced. In this chapter we apply the experience curve concept to estimate the size of future cost reductions. The experience curve concept is also complemented with a bottom-up assessment of sources of cost reduction.

In the text we focus on cost and cost development to the extent that this is possible. However, when cost data is not always available, price data is used. In the early phase of commercialisation it is difficult to define the relation between cost and price. The price can be higher than the cost covering past and future research and development costs; the price can also be lower than the actual cost to boost the market.

### 5.3.1 Cost development of fuel cells – experience curves

Several studies have approached experience curves to analyse the future cost reduction trend of fuel cells. These studies are described below.

Krewitt and Schmid (2004a) discuss information available on fuel cells costs and prices, covering stationary fuel cells and automotive fuel cell systems. The authors discuss the possibility of developing experience curves based on the data available. For *stationary fuel cells* the authors point out that the dominating unit installed is PAFC, a technology not more to be produced. The record of historical data of other types of fuel cells is limited. For small stationary fuel cells (<5kW) cost data is very uncertain. For lager stationary fuel cells (200kW-5MW) the cost data show a large distribution for different alternative technologies, from 3000 to 100,000 euros/kW. Therefore, experience curves will be difficult, or even unfeasible, to develop.

However, the authors draft an experience curve based on cost data for PEMFC and MCFC cost reduction as a function of increased cumulative installed capacity, se Figure 5.5. This curve indicate a cost reduction from approximately 25.000 euros/kW to 10.000 euros/kW moving from app 1000 kW installed capacity to 16000 kW installed capacity. The data has not been used to calculate any progress ratio.

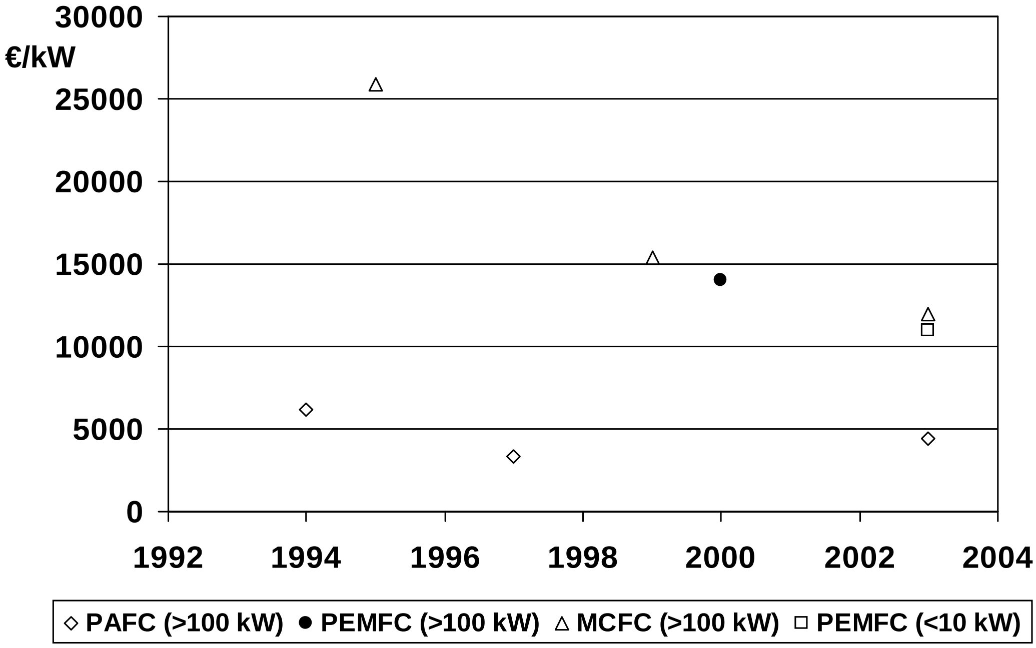


Figure 5.5 Development of specific fuel cell production costs (excluding SOFC) (Krewitt and Schmid, 2004a).

Several other studies approach the use of experience curve for cost analysis of fuel cells. However, they do not develop any experience curves. Lipman and Sperling (1999) discuss cost and prices of fuel cells; they also apply a range of assumed progress ratios (75%-85%) and discuss the differences in outcome. Tsuchiya and Kobayashi (2002, 2004) assume progress ratios for different components of the PEM which they use to discuss future costs. Lipman and Hwang (2003) present a general discussion of experience curves and say that the concept of experience curves is also relevant for hybrid and fuel cell vehicle technology.

In all, the fuel cell technologies are new and no historical data are available to develop experience curves. Moreover the technologies are immature and the technology development paths in the future may be based on radical changes as well as incremental changes; however, only incremental changes are referred to in the experience curves.

If an experience curve for fuel cells is to be used in the modelling work of NEEDS this cannot be based on any experience curve available, neither can an experience curve be developed due to the absence of relevant data. Any experience curve to be used needs to be fictive. One way of defining a fictive experience curve would be to look at other types, and similar types, of technologies. In general, the distribution of process ratios is huge, ranging from 70% to more than 100% (i.e. inclining a cost increase); the average is approximately 80%. Factors influencing the progress ratio are technology type and production process (Neij, 1999). The fuel-cell technologies are to be considered modular technology, which, compared to other types of experience curves indicate a progress ratio of 70-95% (Neij, 1999). The technology will be either small (<5kW) or medium sized (200kW-5MW). Experience curves with a progress ratio of 70% and 95% have only been seen for a relatively modest number of technologies, more likely will be progress ratios of 75-90%. In the studies referred to above, experience curves with progress ratios ranging form 75% to 85% have been applied.

### 5.3.2 Cost development of fuel cells – bottom-up assessment

The installation cost of larger commercial fuel cells (PAFC) today range from approximately 4.000-10.000 euros/kW. These costs are too high and cost reductions are necessary.

The major parts of the fuel cell technologies consists of electrolyte, cathode, anode and catalysts, bipolar plates, seals, reforming unit and balance of plant. Each of these parts are major sources of cost reduction. Additional to this, the production process and maintenance are important sources of cost reduction. The cost reductions could either be radical, decreasing cost by major cost cutting by making radical changes in the product, or in the production process. The cost reductions could also be incremental and based on experience and fine adjustments in the product design of production process.

Key sources of cost reduction for fuel cells are

- Material costs for stack production, i.e. production and supply of platinum group metals, graphite and membranes in the case of the PEFC.

- The fuel stack lifetime is too short and results in a high cost. The fuel stack lifetime is approximately 20.000 hours with target around 30,000 to 40,000 hours (Cotrell and Pratt, 2003). According to Siemens-Westinghouse a stack lifetime of more than 80,000 hours seems to be achievable with the tubular stack concept. For the state-of-the-art 40,000 hours are estimated (Kabs, 2002).

- The cost of the power electronics is too high and needs to be reduced.

- The overall integration of the separate pieces (the reformer, the fuel cell stack and the power electronics) needs to be optimised.

- The production cost is too high. Cost reduction will be required in both the production of single parts (automation) and in the assembling process. The production capacity can be increased by at least triple or quadruple in the near future (Shipley and Elliot, 2004). This will make cost reductions possible.

Material availability may also be a restriction to cost reduction in the future. The large scale production of fuel cells may lead to constraints in material in the future, such materials may be platinum group metals used in PGM, lithium and nickel used in MCFC. However, recycling could be restricting cost increase in the future (Krewitt and Schmid, 2004)

*Cost reduction – PEMFC*
A small number of PEMFC has been installed since 1999 and historical cost data is only available for a few of these (see for example Krewitt and Schmid, 2004b). The investment cost today is approximately 5.500 US$/kW and the maintenance cost has been estimated to 71 US$/kW (Shipley and Elliot, 2004). As far the focus of PEMFC development has been on the performance, incorporating development of the membranes (Nafion) and the election material. The cost of the cell is very high, due to the high membrane material cost, the high cost of platinum catalyst. Cost reductions are foreseen in several ways. For example, Ballard

Power Systems has developed a new membrane, less costly than the Nafion membrane. No figures on cost reductions are to be found in the literature. Long term cost target has been estimated to 1,500-2,000 US$/kW (Tsuchiya and Kobayashi, 2002).

*Cost reduction - SOFC*
The investment cost of the first 100kW SOFC in 1998 was approximately 100,000 euros/kW (Krewitt and Schmid, 2004b). Current cost is approximately 6000 US$/kW and long term target costs has been estimated to 1000 US$/kW for CPH units and 500 US$/kW for small scale systems (Kabs 2002). However, Krewitt and Schmid (2004) find the long term target figures extremely optimistic. The SOFC will be able to operate at high temperatures which will eliminate the fuel reformer and give a competitive (cost) advantage. An alternative key issue for cost reduction of SOFC is to realize operation at lower temperatures, temperatures of 750-850 C rather than 950-1000 C. This would allow less stringent requirements of materials and processes and the use of lower-cost stainless steel materials. Moreover, the material cost of the tubular cells is high. The cost of the tubular cells produced by Siemens-Westinghouse could be reduced by half by developing new tubes with alternative material (Krewitt and Schmid, 2004). The manufacturing cost could be reduced considerable by replacing the present process of depositing the thin electrode and electrolyte layers (i.e. an electrochemical vapour deposition) with a plasma spraying process. For planar cells the material cost is already low, but could be reduced further if cheaper material is used (Krewitt and Schmid, 2004). No figures on estimated cost reductions are to be found in the literature.

*Cost reduction - MCFC*
The installation cost of the first MCFC in 1995 in the US was 23,000 euros/kW (Krewitt and Schmid, 2004b). The size of this was 2MW. Since then, a 250 kW so called Hot Module MCFC has been developed. The current cost of this model is approximately 9,000 euros/kW kW (Leitman, 2005). Only in 2004, the cost of these fuel cells was reduced by 27% (Leitman, 2005). The target cost, according to MTU, is below 1250 euros/kW (Krewitt and Schmid, 2004).Further cost reduction will be gained through simplified system design, simplified production processes and series production. In the BOP system, miniaturization, high efficiency and large scale production processes are the targets. No figures on estimated cost reductions are to be found in the literature.

In all, the learning processes relevant for further cost reduction include learning in doing, i.e. the learning processes related to the design and production of the product. Many examples of changes in the product and production process have been specified above. Relevant to cost reduction is also the learning process covering the use of the product. Learning processes related to the use of fuel cells include the development of distributed electricity generation, off-grid communities and back-up systems. The experience in use will also be relevant for gaining experience in maintenance, which will give feedback to the production and design make possible further cost reduction.

Learning processes will start in niche markets, i.e. the use of fuel cells in microwave repeater stations and off-grid applications. Further commercialisation of fuel cells will be dependent on the development of actor's network including developers, constructors, users, etc. Markets developing in the short term are covering 5-10kW PEM for premium and residential power. At the moment many fuel cell companies have formed strategic alliances with established companies, to enter the market.

### 5.3.3 Cost development of fuel cells – summary

The experience curves of fuel cells indicate cost reductions. However, the costs are high and the bottom-up assessment indicates several important areas in which cost reductions are needed. In a few cases, alternative, less costly options (materials, designs etc) are presented. The cost reductions have, however, not been estimated by figures.

In the NEEDS project we suggest the use of an experience curve with a progress ratio of 80%. The cost reductions pointed at in the bottom-up assessment may very well support cost reduction of this size in the experience curve. However, the sources of cost reduction are vague and it is impossible to say if these assumed cost reductions will support large cost reductions or if these sources of cost reduction will only support minor cost reductions. To underline the uncertainty of the cost reduction we suggest sensitivity analysis applying an additional lower sensitivity value of 75% and an upper sensitivity value of 90%.

## 5.4 Cost development of wind turbines

Wind energy has historically been used to support human activities using traditional wind mills. New innovative wind turbines were introduced in the early 1940s but the real interest in such turbines did not accelerate until the mid 1970s. Since then governmental support has been massive to develop wind technology and markets for wind turbines. Today the wind turbines are an established energy technology alternative and the wind-turbine industry is an established industry. The main driver for wind energy in the 1970s was the domestic source of energy. In the 1980s the arguments added up; wind turbines was considered an important technology mitigating green house gas emission, wind energy was considered clean and safe, the development of the wind turbine technology also provided new jobs.

Since the early 2000s off-shore wind turbines have been developed and installed. The driving forces for off-shore wind turbines are the considerably higher wind speeds off-shore. Wind turbines off-shore are expected to deliver 20-40% more energy then wind turbines on-shore. Off-shore wind turbines also enlarge the area available for placing wind turbines, which will increase the potential for wind energy in total. Nevertheless, off-shore wind turbines are economically less favourable than on-shore wind turbines today. The cost of wind-generated electricity of a medium sized wind turbine (850-1500kW) will be 50-60 euro/MWh in areas with medium wind speed and approximately 40 euro/MWh in coastal areas (EWEA, 2004).

The cost of off-shore wind electricity today is 37-45 euro/MWh (excl. fixed O&M) as in the coastal areas. The wind conditions offshore are slightly better than on the coast but this is offset by higher investments costs as well as higher operation and maintenance cost. In the near future (2015) production costs are estimated to fall to 30-45 euro/MWh and 20-30 euro/MWh in the long term (2025).

Technology improvements and further experience will reduce cost of both on-shore and off-shore wind turbines. In this chapter we will analyse and discuss cost reduction of wind energy applying three different approaches. First, we will apply the concept of experience curves. Then we apply the approaches of bottom-up assessment and long-term expert assessment to verify of changes the results of the experience curve analysis.

In the text we focus on cost and cost development to the extent that this is possible. However, when cost data is not always available, price data is used. In the early phase of commercialisation it is difficult to define the relation between cost and price. The price can be higher than the cost covering past and future research and development costs; the price can also be lower than the actual cost to boost the market.

### 5.4.1 Cost development of wind turbines – experience curves

Experience curves for wind power have been presented in many publications. The cost reduction of these varies considerable. In the following text the system boundaries and data used in the different studies are presented and discussed.

The Extool study presents experience curves based on data of approximately 17.000 wind turbines (Neij at al, 2003; Neij at al, 2004).[10] The study includes data for turbines produced and installed in Denmark, Germany, Spain and Sweden. The study shows that several types of experience curves can be developed based on the data available (turbines produced /installed, by country, by manufacturers; specific electricity production by country and by manufacturers etc.). Moreover, experience curves can be developed for different turbine sizes and for different time periods. Taken into consideration all these types of variations, the progress ratio of the experience curves developed vary between 83%-117%. The general findings of the study say that:

- The experience curves for wind turbines produced (by manufacturers in Denmark, Germany) show a progress ratio of 92-94%. These experience curves include cost reduction in producing wind turbines.

- The experience curves for wind turbines installed (in Denmark, Spain and Sweden) show a progress ratio of 90-96%.[11] These experience curves include cost reduction in producing and installing wind turbines.

- The experience curve for wind turbines in terms of levelised production cost of electricity produced by manufacturers in Denmark show a progress ratio of 83%, se Figure 5.6. These experience curves include cost reduction in producing and installing wind turbines, in efficiency improvements and reduction of O&M cost[12]. When analysing the development of levelised production cost a certain wind class is assumed.

In all, the results show that the expansion of the system boundaries of the experience curves (moving from wind turbines produced to wind turbines installed to also including efficiency improvements) increase the cost reductions observed.

[10] Earlier studies by Neij (1997, 1999), Dannemand and Jensen (1997) and Durstewitz (1999) is partially based on the same data.

[11] The progress ratio for Denmark is 90% and for Spain 91%. The Swedish experience curve show a progress ratio of 96% - however, the data is limited to a short time period and excluding the first data point result in a progress ratio of 89%. It is recognised that the progress ratio also for Denmark and Spain is sensitive to the time period used.

[12] The levelised production cost of electricity, expressed as cost/kWh is based on the specific electricity production of wind turbine produced in Denmark (at roughness class 1), cost reduction of installation of wind turbines in Denmark, a lifetime of 20 years, an interest rate of 6%, and O&M costs calculated according to a model developed from the results of a number of questionnaires surveys (Redlinger, et al., 2002, pp. 77-80)

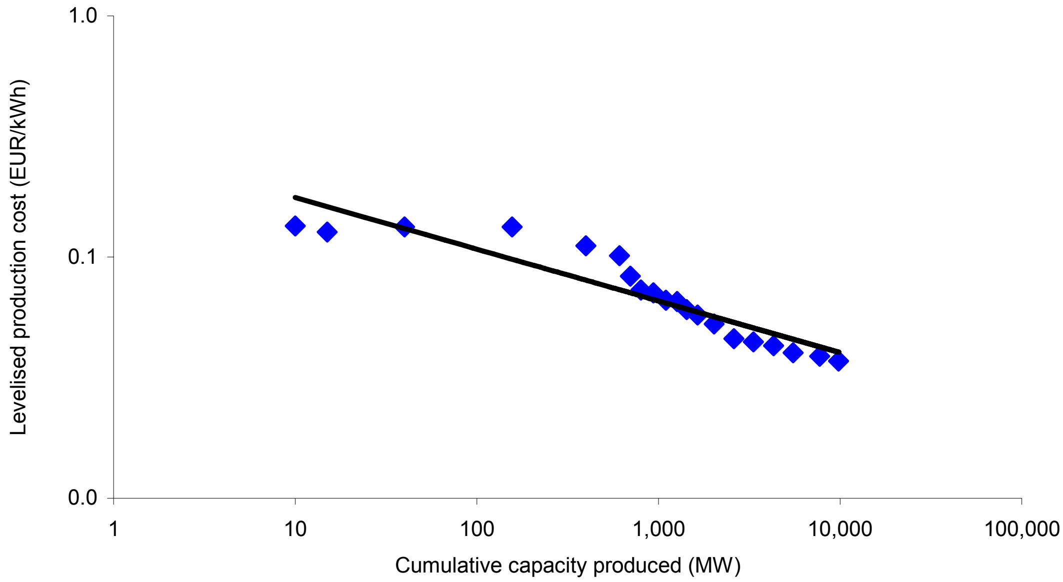


Figure 5.6 Experience curve for levelised production cost for wind turbines made by Danish manufacturers, 1981-2000 (PR=83%, $r^2$ = 0,97). Costs are expressed in 2000 year prices. (Neij et al., 2003)

The experience curves developed in EXTOOL do not cover cost of electricity generated by wind turbines. Such curves are very difficult to develop, since the required data are usually not publicly available. One way to estimate the reduction of electricity cost would be to use the experience curve of levelised production cost of electricity and to say that the this curve do not include all sources of cost reduction, and that the actual cost reduction most probably have been higher – considering a certain wind class.

Junginger et al. (2004a) present more progressive cost reductions for installed wind turbines and experience curves with progress ratios of 81-85%. The experience curves developed are based on the global cumulative installed wind power capacity and prices of installed wind power in Spain and the UK. The authors argue that the wind power installed in Spain and the UK represent wind investments with low profit margins and thus give a truer picture of the cost development. A comment to this will be that price data applied for Spain is the same as in (Neij at al., 2003) but a different time period is chosen. This indicates the sensitivity of the timeframe used in the studies. Another comment will be on the experience curve of installation cost in the UK. The actual installation cost of wind turbines in the UK study is much higher than the actual cost in any other country; the experience curve is also based on much smaller wind turbines than in other countries. So, starting the experience curve with relatively high cost figures and over time approaching the lower cost figures applied in other countries the cost reductions should be higher. In all, the presented progress ratios illustrate extremely high cost reductions.

Ibenholt (2002) present experience curves based on the tariff prices of wind-generated electricity in Denmark and Germany. However, the tariff prices are set by the government and do not show the actual reduction in cost or price of wind turbines or generated electricity. Experience curves based on tariffs for the electricity are thus not relevant for the analysis of wind power development.

Rough estimates on the progress ratio for cost of generated electricity are to be found in OECD/IEA (2000). The progress ratio of wind energy generated in EU 1980-1995 is presented as 82% based on figures form the EU-ATLAS project. However, it is not clear to what extent the figures are based on actual costs or price tariffs. The progress ratio of wind generated electricity in the US 1985-1994 was estimated to 68% - based on prices data in the US from Kline (1998) and electricity generation from Gipe (1995). The relevance of these figures would require a deeper analysis of the data used.

The only publication on offshore wind turbines is written by Junginger et al. (2004b). The publication does not present any experience curve for the system as a whole but present experience curves for different sub-systems. The authors estimate the experience curve for wind turbines off –shore to be the same as for wind turbines on land and refer to the article by Junginger et al. (2004a).[13] Considering the grid connection experience curves for submarine HVDV cables and HVDC converter stations were developed. The progress ratio of these curves was estimated to 62% and 71%, respectively. For foundations, relevant experience curves were not presented, but judgements on cost reductions are used. The installation cost varies a lot and experience curves with progress ratios of 77% and 95% were developed. Based on these figures future cost of off-shore wind was calculated.

Some publications present studies on future cost development based on assumed progress ratios in the range; Kouvaritakis et al. (2000) assumes a progress ratio of 84%.

In all, the experience curves on wind power clearly show that there is not one progress ratio but that the progress ratio will depend on factors such as timeframe, system boundaries, geographical area etc. Due to this the uncertainty in what progress ratio to use when forecasting future costs is also high for wind energy technologies, although wind technology is a relatively mature emerging technology.

### 5.4.2 Cost development of wind turbines – bottom-up assessment

In the EXTOOL project the development of modern wind turbines and sources of cost reduction has been analysed and discussed (Neij et al., 2003; Neij at al., 2004). The study show that the cost reduction of wind turbines was reduced by approximately 50% between 1981 and 2000 and that the cost reduction of wind turbines – also taking into account installation cost and O&M cost - has been more than 60% between 1981 and 2000.

The identified key process in the technological development of wind turbines has been *up-scaling*. Each generation has been larger than the preceding generation, measured as rated capacity, swept rotor area, etc. However, cost reduction of wind turbines is presented as the result of three different types of technological innovation - innovation in one size machines, up-scaling on a platform and introduction of a new platform (Neij et al., 2004; Dannemand Andersen, 2004). Innovation in one size machines refers to learning through manufacturing and technological changes. Up-scaling on a platform have involved higher cost reductions since changes have been made to the design of a machine at the same time as being up-scaled: all the experience from earlier designs have been embodied into the scaled up design. The introduction of a new platform have lead to cost reductions due to significantly increased rated capacity and rotor diameter, but also the introduction of new technological features, such as new drive-train solutions.

[13] These calculations of the progress ration were, however, based on installation costs also including foundation, grid-connection etc.

Each new generation of turbines has been designed conservatively with broad safety margins. After some experience of turbines had been gained, these safety margins could be narrowed down. Typically, the experience gained has not been used to produce the same design cheaper but to increase the electricity output by means of a slightly larger rotor diameter, a change in pitch angle, etc. Based on our analysis of the data available it appears to be almost impossible to distinguish between reductions due to technological learning and those due to scale effects.

Cost reduction of electricity production has been relatively larger than cost reduction of wind turbines. The cost of electricity has been reduced due to items such as foundations, electrical installations, grid connection, financial costs, civil engineering planning and consulting, roads, etc. Experience shows that, the costs for foundations, road construction, and grid connection decreases significantly with the number of turbines in each project. Additional costs, expressed as a percentage of the total cost, have decreased during the past 20 years. Danish investigations indicate that in 1989 almost 29% of the total investment cost was related to costs other than that of the turbine itself. By 1996 this had declined to approximately 20%, a level that been maintained over the past five years. The additional cost have also been estimated based on Danish data from comprehensive questionnaire surveys carried; this survey show a cost reduction of almost 60% from 1980 to 2000 (Redlinger et al., 2002). Moreover, cost reduction of electricity will depend on siting, wind capture and O&M costs.

Estimates of future cost reductions of wind turbines and wind generated electricity needs to capture cost reduction estimates of both on-shore and off-shore wind turbines. The sources of cost reduction of these two systems will however look different. The investment of an on-shore wind turbine represents approximately 75% of the total investment cost; the investment of an off-shore wind turbine represents approximately 30-50% of the total investment cost (Junginger et al., 2004b). In the case of off-shore wind turbines the cost of foundation, installation and internal grid and grid connection to shore is much higher than for on-shore wind turbines. In all, the sources of cost reduction will be different for the two systems.

On-shore wind turbines will probably continue to decrease in cost. Prices may however increase due to a large demand and generous subsidies. As historical cost reductions can be describes as a result of incremental technology improvements, future cost reductions are very much likely also to rely on incremental improvements. No one can say today what the technical and economical limits of turbines will be. In the future turbines will be specially designed for special conditions. At present, the largest turbines being developed are in the 5 MW range. However, small plants in the kW range will also find growing markets, for example, as integrated supply modules in hybrid systems for power supply in remote areas. Cost reductions are expected for all types of wind turbines.

As fare the experience in cost reduction of off-shore wind turbines have been limited. The installations are few; they have different sized and different types of foundations. The location of the off-shore wind turbines have moved further out in the see – from low water depth close to the coast to distant location with deep water. This to improve the wind capture and the capacity of the turbines.

In the case of off-shore wind turbines, the tower used has been approximately the same as the on-shore wind turbines and thus refers to the historical cost reductions described in the text above. Future sources of cost reductions identified are design improvements and up scaling, faster rotation speed, larger capacity generators per unit of rotor area and high voltage generation (Junginger et al., 2004b). At first off-shore wind turbines were installed using vessels, barges and cranes for the oil and gas industry and costs were fluctuating strongly (Junginger et al., 2004b). In 2003 purpose-build ship were used for the first time and the average installation time was reduced considerably (Junginger et al., 2004b). This in turn, reduced the installation cost considerably.

Some experience have been gained regarding foundation; different foundation concepts have been tested- including tripod structures, steel monopiles and box caisson structures. According to Junginger at el. (2004b) cost reduction could be the result of mass-production rather than custom-made units, i.e. a standardisation of foundation design. Cost could also be reduced due to falling steel prices. New types of foundations envisioned are suction caisson (bucket) foundation, guyed tower, floating foundation and self-installing concepts using telescopic towers (Junginger et al., 2004b). These may very reduce cost in the long-term. Junginger et al. 2004 also discuss cost reduction of grid connection illustrating the cost reduction in HVDC cables, HVDC converter stations and internal grid connections. However, figures are not presented for potential cost reductions in the future. Based on historical data experience curves for the sub-systems have been developed indicating a progress ratio of 62% in one system and 71% in another system.

Only few general foresight studies and roadmaps for wind power technology in the long-term perspective exist. Offshore wind technology is usually dealt with as part of the broader wind energy field. European Wind Energy Association (EWEA, 2002) published the Wind Force 12 report, in collaboration with Greenpeace. The later versions of the report include new additional perspectives respectively on the future of offshore wind systems specifically and on global perspectives of wind power (EWEA, 2004 and GWEC, 2005). Also a more limited foresight on wind power technology focusing on environmental aspects and the removal phase of the life cycle of wind turbines exists (Dannemand and Bjerregaard, 2001). Assessments of future cost are also made in BTM Consult 2004a and 2004b. Moreover the future of wind power technology is represented in a number of reports going across different energy technology areas, e.g. EREC, 2004; EUREC, 2002; IEA, 2002; Larsen and Petersen, 2002 and IEA, 2005.

### 5.4.3 Cost development of wind turbines – long-term expert assessment

The work with identifying expert-based knowledge of the future wind power systems and their costs consists of interview meetings with selected experts. The interview meetings are interviews and discussions with typically a couple of experts plus a couple of person from the NEEDS project group. The interview meetings are set-up as semi-structured conversations. Initial parts of the interview meetings to some extend have character of brainstorming. In addition to the interview meetings a number of more limited phone interviews has been carried out. The interviewed experts are primarily technical experts from manufacturers and consultants and developers in the wind power area. Some of the interviewees are experts on wind power systems generally while other are experts on specific key elements for the future technology e.g. on offshore turbines and their foundations.

Compared to the foresight literature, presented in 5.4.2, the interview meetings only to a much more limited degree can describe a complete picture of the future costs of wind power systems; all the more so as also other aspects than the costs aspects are to be addressed in the interview meetings. The interview meetings however on some points have offered valuable insight for overall assessment of the future costs.

As described in Neij et al. (2003) there is different perspectives/ types of cost reductions and experience curves:

- Production perspective
- Market perspective

These approaches have not been investigated in all details, but some examples have been discussed with the experts. According to experts pig iron (untreated steel) costs in the neighbourhood of 1 euro / kg where the kg price in the end product – shaped, welded, painted etc. - is around 1,8 euro / kg i.e. a great part of the costs of steel foundations and towers follow the market costs of steel (Bonus/Siemens). Learning from a production perspective can in this case only influence a smaller part of the product price.

Choice of materials is also changing with the development of larger and more efficient wind turbines. For example the blades are today produced with epoxy and fibre glass, but in the future a larger part of the blades will be produced with carbon fibres because of its better performance. But also in this case market prices on the fibres are an important element in the end product price. According to Bonus/Siemens the better performance of carbon fibres – and the higher price - is evaluated against the characteristics of glass fibres every time a new wind turbine prototype is in the planning. So far they have found that the price of carbon fibres is still to high compared to its performance, and they have stuck to glass fibres. Market prices for fibre glass and carbon fibres are in the neighbourhood of 3 euro/kg and 15 euro/kg respectively – but few years back carbon fibres were 100 euro/kg.

Most engineers prefer steel foundations for offshore wind farms, but few wind farms has chosen concrete foundations based on a comparative study of performance and price. Nysted wind farm for example is based on concrete foundations. In the future where the foundations will be met by higher demands due to larger turbines and greater depths again the choice will be a trade off between technology and material prices.

From a market perspective an important issue to be addressed is the margin between the actual costs of producing an offshore wind farm and the contract price, which is a result of supply and demand of wind farms. Several experts has described a tendency to increasing contract prices for offshore wind farms due to the increasing demand for both offshore wind farms – and onshore wind farms, especially in the US (see for example BTM Consult at the Copenhagen Offshore Wind Conference 2005a,b). In other words the observed contracts prices are not indicative for the actual manufacturing costs which are most likely reduced due to learning, but represent the equilibrium price in the marked where producers makes good profit on the large – politically driven - demand.

Another explanation on rising contract prices has also been suggested to be the high element of risk in the offshore business. The first years of experience has shown that offshore wind turbines have a higher risk of breakdown and therefore there’s a higher risk that producers has larger costs in the guarantee period.

The experience from the analysis work reflected above is that the direct input from experts e.g. in interview meetings etc. are seldom as complete descriptions as in the written expertise-based reports based on expert assessments. The oral communication and discussions with experts can not directly in itself and independently describe a full picture of the costs. At least not as long as it is only a relatively limited amount of interviews etc. there is made. However, as a reflection processes for the analyst and a way of discussing the existing material and bringing the different analysis together, the direct meetings with the experts are important.

### 5.4.3 Cost development of wind turbines – summary

The experience curves for wind turbines indicate cost reductions. However, we would like to stress the differences in cost reduction illustrated based on the different system boundaries applied. The cost reductions illustrated in the experience curves is further supported by bottom-up assessments. Historical sources and potential sources of incremental cost reductions for wind turbines have been illustrated for on-shore wind turbines. Historical data also show that cost reduction of wind generated electricity is much higher than for wind turbines. If including efficiency improvements and reduction in additional costs and O&M, cost reductions are much larger. Experience curves for future wind energy will therefore be more progressive.

Based on incremental improvements in already existing technologies we suggest a progress ratio of 90% for on-shore as well as off-shore wind turbines. To underline the uncertainty we suggest a sensitivity analysis of applying an additional lower sensitivity value of 88% and an upper sensitivity value of 92%. However, these figures do not capture efficiency improvements and the larger cost reductions of generated electricity. To capture also this we suggest a progress ratio of 85% for wind turbines placed in less windy areas (VC 2 and 3) and a progress ratio of 80% for off-shore wind turbines and wind turbines placed in more windy areas (VC 1).

## 5.5 Cost development of photovoltaics (PV)

Several different types of PV systems have developed over the last decades; the main PV systems developed can be characterised as

- Off-grid domestic (stand alone) systems
- Off-grid non-domestic installations
- Grid-connected distributed PV systems
- Grid-connected centralized systems

In this project we include only grid-connected systems, which dominate the market today. In 2003, the most common application was the grid-connected building-integrated systems, accounting for approximately 60% of the cumulative installed capacity (IEA, 2006). Prognoses tell us that the demand for this application will increase. The demand of centralised systems has been limited due to the high costs and the large amount of land area required.

PV systems are to be seen as integrated systems; including the module (i.e. combined solar cells which convert solar to energy) and Balance of System (BOS) covering additional components such as the electrical connection and the mounting structure.

The dominating modules today are the crystalline silicon PV modules which accounts for approximately 90% of the market. These can be either single crystalline silicon (c-Si) modules or multi-crystalline (mc-Si) modules. The other type of modules available on the market today is the thin film PV modules, e.g. amorphous silicon, cadmium telluride (CdTe) modules and copper-indium-diselenide (CIS) modules. For the BOS systems many different applications exists. For the building integrated systems the BOS will depend on if it is a retrofit installation on existing building or an integrated systems in new buildings and what type of function of the used surface will have (roofs vs. facade) etc.

In the future improvements of existing modules and BOS are expected. Moreover, new technology options are likely to constitute the envisaged future and the long-term future PV technology spectrum will be much more differentiated than today to serve different market segments and needs.

The key issue for further diffusion of PV will be cost reduction – cost reduction covering all types of PV systems. The pathway of cost reduction will need to be supported with improvements in efficiency, improvement in terms of BOS, system reliability, good maintenance, improved overall system performance, availability of surface, visual integration, integration with energy-passive devices, social acceptability etc. The question is how much and how fast costs can be reduced. In this chapter we apply the experience curve concept to estimate the size of future cost reductions. The experience curve concept is also complemented with the analysis of sources of cost reduction and experts' opinion of cost reductions.

In the text we focus on cost and cost development to the extent that this is possible. However, when cost data is not always available, price data is used. In the early phase of commercialisation it is difficult to define the relation between cost and price. The price can be higher than the cost covering past and future research and development costs; the price can also be lower than the actual cost to boost the market.

### 5.5.1 Cost development of Photovoltaic (PV) – experience curves

To analyse future cost reduction many studies based on experience curves have been developed. The progress ratios of the studies developed vary widely – from 53% and 90%, see Table 5.7. However, the studies do not describe the same PV system and do not use the same system boundaries; different types of technologies and technology systems are covered, different geographical areas are applied and different time periods are used. Most of the studies are based on PV modules only, probably crystalline silicon. Some of the studies have a national perspective; others a global perspective.

In general, the progress ratio for the PV *modules* is approximately 80%, or ranging form 77% to 82%, se figure 5.7. The experience curves for PV modules in Germany and the Netherlands show a much slower rate of cost reduction and a progress ratio of 90%. The experience curve by Maycock (2002) show a progress ratio of 72%; however, it is not clear if this curve also include thin film modules.

Schaeffer et al., (2004) separates the costs of modules and BOS, saying that module prices are determined globally and BOS locally. In Germany, the support policies have been massive resulting in a huge increase in market demand. This, in turn, has resulted in reductions in BOS cost but not in module prices. Schaeffer et al. (2004) observed that the progress ratio may change over time (c.f. the results of Neij et al. 2003 on wind applying different time frames). The results also show that the prices were not reduced constantly but that periods of stable prices were followed by periods of considerable price reductions. This indicates that if using shorter periods of time the calculated PR may be too optimistic or pessimistic.

Table 5.7. Experience curves developed for PV

| PV system | Geographical area | Time period | PR | Source |
|---|---|---|---|---|
| PV modules (crystalline silicon) | Japan | 1979-1988 | 79% | (Tsuchiya, 1992) |
| PV modules | USA | 1976-1988 | 78% | (Cody and Tiedje, 1997) |
| PV modules | USA | 1976- 1992 | 82% | (Williams and Terzian, 1993) |
| PV modules | | 1981-2000 | 77% | (Parente et al., 2002) (data source unknown) |
| PV modules | | 1968-1998 | 80% | (Harmon, C. 2000) (several different data source) |
| PV modules (crystalline silicon) | | 1976-1996 | 84%, 53%,79% | (OECD/IEA, 2000)(based on the EU atlas project and Nitsch 1998) |
| PV modules | Germany | | app. 90% | (Schaeffer et al., 2004) |
| PV modules | the Netherlands | | app. 90% | (Schaeffer et al., 2004) |
| PV modules | Globally* | 1976-2001 | 75-80% | (Schaeffer et al., 2004) |
| PV BOS | Germany | 1992-2001 | 78% | (Schaeffer et al., 2004) |
| PV BOS | The Netherlands | 1992-2001 | 81% | (Schaeffer et al., 2004) |
| | | | 74% | Maycock, 2002, referred to in Nemet, 2006 |
| PV modules | | 1976-2001<br>1987-2001 | 80%<br>77% | Strategies Unlimited, referred to in Schaeffer et al., 2004 |

* The Photex study (Schaeffer et al., 2004) is based on 3600 units and 26 MW installed capacity in Europe over a 10 years period. List prices are used.

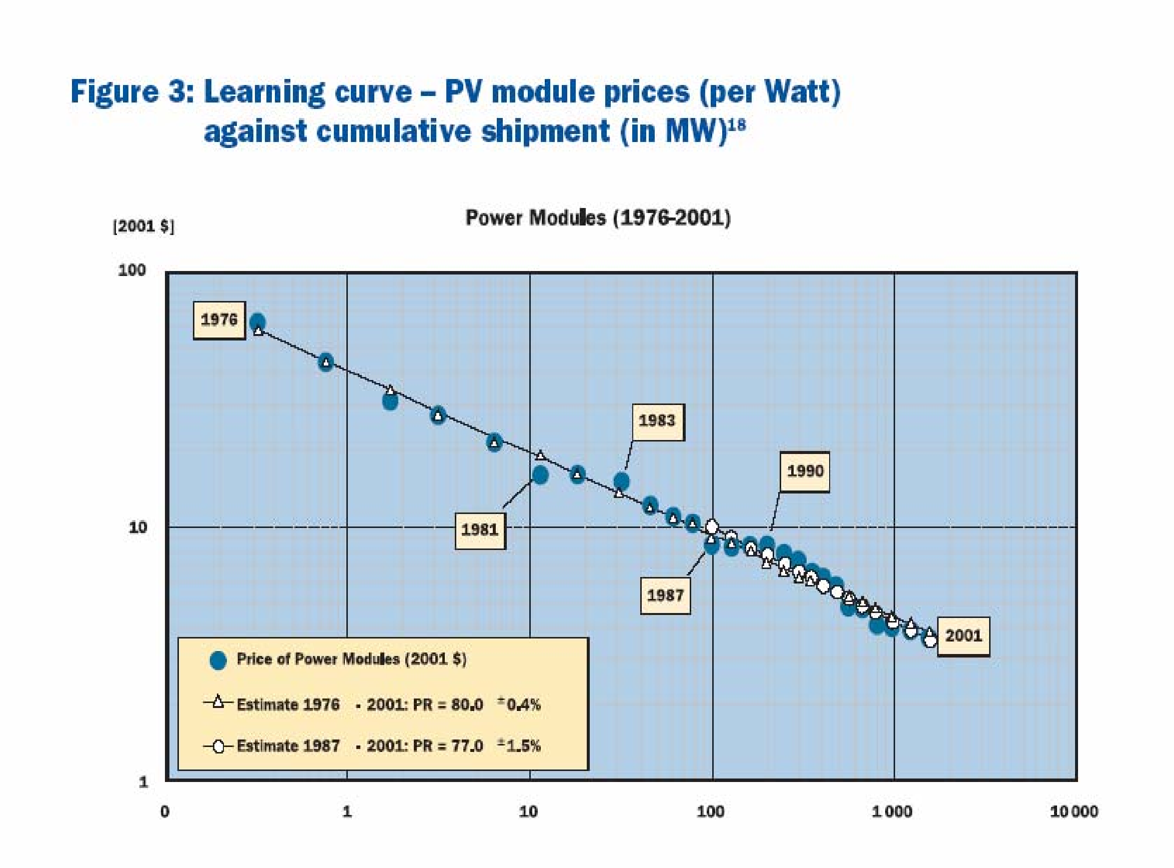


Figure 5.7. Experience curves developed for PV (EC, 2005).

A rough estimate on the progress ratio for cost/price of *generated electricity* is to be found in OECD/IEA (2000). The progress ratio of solar generated electricity in EU 1985-1995 is presented as 65% based on figures form the EU-ATLAS project – it is not clear to what extent the figures are based on actual costs or on price tariffs. OECD/IEA (2000) also present differences in progress ratio for different periods – referring to the price cycle of BCG, see section A2.

Several publications present studies on future cost development based on assumed progress ratios in the range of 70-90% (see for example Neij (1997), van der Zwaan and Rabl (2002), and Schaeffer et al. (2004)). The results of these studies indicate that small changes in progress ratio will have significant influences in calculated cost development.

In all, the experience curves for PVs, presented in table 11.1, have shown a progress ratio of approximately 80% for PV modules. The studies of BOS indicate a similar progress ratio – however this will probably differ between countries. The experience curves illustrate experience and cost reduction in already installed units with a focus on grid-connected distributed PV systems using modules of crystalline silicon. Incremental improvements and further experience in production and installation of such systems will probably relate to an experience curve with a progress ratio of approximately 80%.

However, PV systems develop and other modules and PV systems are being introduced on the market. The introduction of a larger share of thin film modules will change the prospects of cost reductions. Cost reductions of new innovative PV systems may very well relate to another progress ratio and more or less progressive cost reductions. To use these experience curves based on the historical technology development will in these cases be of limited relevance.

In general, it will be difficult to represent all PV systems with one experience curve. It will also be difficult to provide any progress ratio for PV generated electricity.

### 5.5.2 Cost development of Photovoltaics (PV) – bottom-up assessment

Several studies have stressed the importance of cost reductions for the PVs and several sources of cost reduction have been described in roadmaps covering PV development (se for example EC, 2004; EC, 2005; EPIA, 2004a; EPIA, 2004b; RWE, 2004)). The reports are produced by different kinds of institutions: some are made by the research community while others are made by the industry association (one of these in collaboration with an environmental NGO). This means that it is a relatively broad covering of the subject that is offered, also with respect to the expertise areas represented. The European perspective is clearly reflected, however international aspects are also represented.

The target of cost reductions in the medium term, approximately 2030, has been set to 0.5 euros/W for modules and 1 euro/W for systems.[14] This cost reduction will be the result of an improvement in efficiency of flat-plate PV systems; reaching 10-25% in 2030 and 30-50% in a longer term. Moreover, the lifetime is expected to increase to 35-40 years and the operating

[14] Keshner and Arya (2004) illustrate a factory, covering five sub-factories, which will provide solar panels of $1.00 per watt installed system. The panels are based on thin-film active layers and interconnected panels with coated aluminium rails.

and maintenance cost is expected to decrease to 0.5-1% of the investment cost. At the same time new alternative PV will be developed such as dye-sensitised photochemical solar cells, conducting polymer cells, quantum solar cells and modular organic solar cells to reduce costs.

In the text below we describe the of cost reductions of silicon modules, thin film modules and BOS.

*Silicon modules*

Historically cost of PV modules has been reduced. Nemt (2006) identify several sources of cost reduction for the time period of 1975 to 2001, these are

- The efficiency and the rated output per square meter has almost doubled
- The yield has increased due to improved processing technique
- The silicon consumption (per watt) was reduced by a factor of 1.5
- The cost of silicon was reduced by a factor of 12.
- The share of poly-crystalline modules increased and it may be assumed that these modules cost 90% of the mono-crystalline modules
- Improved crystal growing methods made it possible to increase the cross-sectional area by a factor of four
- The manufacturers enlarged their facilities

Nemt (2006) has further modelled the importance of the different factors for two time periods 1975-79 and 1980-2001. In the first time period, a period when the market share for PV applications in space-based satellite applications was reduced and terrestrial applications overtook the domination of the market, costs were reduced by a factor of three. According to the model used in the study, changes in costs were mainly referred to three of the identified sources of cost reduction – efficiency improvements, cost reduction of silicon, and increase in plant size. However, 59% of the total sources of cost reductions could not be explained by any of the given factors. The additional sources of cost reductions were assumed to be

- Differences of willingness to pay for space-based satellite applications vs. terrestrial applications which resulted in a difference in technology quality and in relation of cost and market price
- Increasing competition leading to decreasing prices
- Standardisation and changes in production methods

In the second time period, 1980-2001, costs were reduced by a factor of seven. This time 95% of the cost reduction could be referred to the identified sources of cost reduction, described above. 43% of the cost reductions were related to plant size, 30% was related to efficiency improvements and 12% was related to cost of silicon. Other sources of cost reduction, i.e. yield, silicon consumption, wafer size and poly-crystalline share, accounted for less than 3% of the total cost reduction.

Sources of future cost reductions have been identified in additional studies, such as Schaeffer et al. (2004) and EC (2005). In the following text we present sources of cost reduction often highlighted:

- *Decrease the amount of silicon required.* The Photex project (Schaeffer et al., 2004) present estimations of cost reductions by 8% as a result of reduction of silicon usage by 20%. The cost reduction will be through improved slicing, vapour etching, improve packaging and lower cost silicon. Important will also be low the cost reduction of purification routs. The cost development will also rely on the availability, quality and price of silicon feedstock.

- *Increase efficiency*. The Photex project (Schaeffer et al., 2004) present efficiency improvements from 14% to 17%, in the near term, which will reduce costs by 17%. The efficiency improvements will be through process control, hydrogen passivation and black surface modification. The goal in a longer perspective is advanced cell designs and processing schemes for even higher efficiencies, i.e. 22% on a cell level and 20% on a module level.

- *Increase yield*. The Photex project (Schaeffer et al., 2004) present yield improvements from 85% (?) to more than 95% which will reduce costs by 4%. The improvements will be through elimination of gross failure sawings, and the preparation for thin wafers.

- *Increase in scale*. The Photex project (Schaeffer et al., 2004) present estimated cost reduction of 25% is scale increase form 10 to 100. The increase in scale needs to be supported by volume purchasing, balanced line, larger equipment and higher throughput. Increase in scale will also make possible the development of lower cost, standardized, fully automated process equipment.

*Thin film modules*

The studies on thin film modules are much more vague on quantifying historical as well as future sources of cost reduction. Several studies identify necessary technology improvements for further diffusion, some of these improvements will lead to cost reductions. Key issues that are likely to reduce cost of thin film modules will be stabilise module efficiency, improved process yields and improved encapsulation. By 2030 silicon thin film modules might reach efficiency as high as 18%, which will have a huge impact on cost reduction and facilitate cost effective power applications (see NEDO, 2004 and Hoffmann, 2004). CIS/CIGS modules also seem very promising in the short to medium term due to their high efficiency (around 11% in 2005, with a significant potential for improvement). The efficiency of the CdTe module is lower, but the production costs are lower. For all thin-film modules cost reduction may be limited by restricted material availability (especially with respect to indium and tellurium). Other issues highlighted in the literature that will support the reduction of costs are the development of new thin film concepts, the development of multi-junction structures, the development of low-cost, high-per performance TCO materials for thin-film cell designs, reduced materials consumption and use of low cost, low-grade materials, development process for of low-cost production etc.

*Other types of modules*

In the near term modules that will be a combination of crystalline and thin-film technology will appear on the market, i.e. a-Si/µc-Si and silicon thin-film modules. These take advantage of the high efficiencies of silicon modules and the lower material consumption and larger deposition areas of thin film modules. The cost reduction of such modules will be promising. More innovative alternatives like modules based on dye-sensitised photochemical solar cells, conducting polymer cells, quantum solar cells and modular organic solar cells are also being developed. Other types of low-cost modules that may enter the market in a medium term will be a-Si pin (“Solar electricity glass”) which will nevertheless meet important market segments, such as large skyscraper facades (Hoffmann, 2004).

*BOS*

As described above, BOS will look very different form one system to another. For this reason experience may be limited in the different systems and the possibilities for cost reduction may be restricted. In the Photex project (Schaeffer et al., 2004) it is stated that most of the cost reductions related to the mounting structures have already been realised. These cost reductions where mainly due to choosing galvanised steel instead of aluminium profiles. Additional cost reductions may be due to integration of the components and reduction of the labour force.

In general, the inverter relate to approximately 40% of the BOS cost and is therefore important for any potential cost reductions of the BOS. Some options that will be relevant for cost reduction in the future will be to use of high-frequency dc/dc converters, to use high voltage PV modules and to integrate semiconductor components and harmonisation of regulations. Current cost of 0.5 euros/Wp (larger systems) to 0.8 euros/ Wp (smaller systems) can come down to 0.2 euros/ Wp (larger systems) to 0.4 euros/ Wp (smaller systems) (ref).

### 5.5.3 Cost development of Photovoltaics (PV) – long-term expert assessment

In the area of photovoltaics, a relatively large number of road maps and technology foresight studies exist, see section 5.5.2. The data of these reports have been confirmed by oral interviews with PV experts; the results of these interviews are presented in this section. The experts are from industrial companies and firms producing PV modules or full PV systems, as well as from companies working with building integration and multifunctional systems. Moreover, scientific experts and researchers in the PV area have been addressed. Also experts from the industry associations have been consulted. In many cases, the experts could provide insight in both expected developments in the technology in general and in more specific cost issues related to assessments of specific resource uses and material flows. The oral assessments by PV experts have generally not resulted in completely different or opposite assessments of the costs compared to the assessments in the written reports.

While the whole set of costs was mainly taken from written documents, some more specific cost issues and specific data were discussed with the individual experts. The experts were for example Benhard Dimmler, Wuerth Solar, Germany and Dieter Bonnet formerly Antec Solar, Germany concerning the costs of thin films, and Erik Alsema, Copernicus Institute for Sustainable Development and Innovation, Utrecht University, the Netherlands and industry expert Daniele Margadonna concerning the costs of c-Si modules. The general costs of PV modules and systems were discussed with e.g. Roberto Vigotti, Chairman of IEA, REWP, while the costs of BOS were discussed with among other Cinzia Abbate and Carlo Vigevano, from Abbate & Vigevano, Italy, who are related to architecture and building design in connection with PV system.

A selection of expert assessments is provided below. The selection shows examples of some of the central aspects separately for modules, systems and electricity cost. It includes assessments on some of the connected requirements and assumptions for the developments.

On *PV module costs* EC (2005) cites (p. 20): "The price of standard PV modules is currently approximately 3 €/W. This could be reduced to 2 €/W by 2010, 1 €/watt-peak in 2020 and 0.5 €/W in 2030. After 2030 a further price reduction is expected. These figures are supported by the historic learning curve for PV modules, which shows a 20% price reduction for every doubling of the accumulated sales. Cost reduction can only be achieved by continued market growth in combination with focused research efforts, and with cross-fertilisation and spin-offs from other high-tech industry sectors like flat panel displays, micro-electronics, nanotechnology, the automotive industry and the space sector."

RWE (2004) cites (p.8) that "Since the already industrialized PV technologies still promise potential for further development, and "next generation" technologies are well underway, a strong confidence is justified to postulate that the experience curve will also extend into the future. With the increasing economy of scale material cost contributes relatively more and more to the total cost of a module. In order to account for that the learning factor is decreased from 20 % down to 18 % and even pessimistically to 15 %. The continued experience curve thus indicates, depending on the assumption of the learning factor between 15 and 18%, that the 1 €/Wp cost level will be reached at an accumulated production of around 100 GW, which according to the projected growth will occur around the 20ies."

Assessment on *PV systems costs* are among other places found in EPIA (2004a). In this study the cost goal of 2010 range from 6€/Wp (for 5 kWp system) to 3.6 €/Wp and in 2020 the cost goal reaches 2€/Wp. The assumptions are based on a 5% price reduction per year for all components covering modules, inverters and installation.

EC (2004, p. 16.) states that "For a system price of 1 €/Wp the electricity cost is between 0.05 and 0.10 €/kWh, depending on insolation and interest rate (financing scheme). At these cost levels PV is interesting from the consumer's perspective and for peak power production. For bulk power, high insolation and good financing schemes are needed at a systems cost level of 1 €/Wp. However even now, at system prices of 5 €/Wp or higher, PV is interesting in markets where electricity is expensive (off-grid) or added value can be cashed, like building integration. Not taking into account are external costs that favour the clean renewables, the advantage of a diversity of sources (security of supply) or shortage of fossil fuels giving an increase of electricity costs. This will favour the market penetration of PV."

Moreover, on assessing systems costs EC (2004) cites (p. 23): "Turn-key system prices in 2004 are typically 5 €/W (excl. VAT), even if dedicated designs and some applications require higher material, engineering or installation cost […] Detailed analyses of the potential for price reduction have shown that system prices may be reduced to 3.5 €/W by 2010, 2 €/W by 2020 and less than 1 €/W in the long term (i.e. 2030 and beyond). Studies are being carried out to determine the lowest achievable price. This knowledge is important for the competitiveness of PV in future bulk electricity markets. Since the BOS accounts for roughly 40% of the turn-key system cost, drastic cost reductions are required in this area along with cost reduction of modules. Two topics require particular attention: inverters and mounting/building integration of modules."

RWE (2004) cites (p. 5) "For solar electricity, an additional parameter, the geographical location of the PV installation, directly influences the generating costs, due to the corresponding insolation. In Germany, e.g., 1-sun insolation amounts to 900 h/year, while in Southern Europe it is 1800 h/year. In Fig 12, reference is made to turnkey prices for PV solar electricity systems during the past 10 years in Germany. Starting from the early 1000-roof program in Germany in 1990 customers had to pay about 13 €/Wp installed system which in 2000 is decreased to 8 €/Wp. This corresponds to an annual price decrease of about 5%."

The assessments of *PV electricity costs* are among other places found in EPIA (2004b) (pp. 32-33): In terms of delivered electricity, it is possible to make predictions for the output from grid-connected systems. The results are given for an average consumer in some of the major cities of the world (see Table 5.8). These show that by 2020 the cost of solar electricity in the most insolated regions - the Middle East, Asia, South America and Australasia - will have more than halved to as little as 10-13 S cents/kWh in the best conditions. This would make PV power competitive with typical electricity prices paid by end consumer households.

Table 5.8 Price development of PV electricity in selected cities 2000-2020 (EPIA, 2004b).

**Table 4.4: Fall in Price of PV electricity in selected cities 2000-2020**

| Region | kWh/ (year* kWp ) | 2005 €/ kWh | 2010 €/ kWh | 2015 €/ kWh | 2020 €/ kWh |
|---|---|---|---|---|---|
| Berlin | 900 | 0.40 | 0.30 | 0.26 | 0.19 |
| Paris | 1000 | 0.36 | 0.27 | 0.24 | 0.18 |
| Washington | 1200 | 0.30 | 0.23 | 0.20 | 0.15 |
| Hongkong | 1300 | 0.28 | 0.21 | 0.18 | 0.13 |
| Sydney | 1400 | 0.26 | 0.19 | 0.17 | 0.13 |
| Mumbai | 1400 | 0.26 | 0.19 | 0.17 | 0.13 |
| Bangkok | 1600 | 0.23 | 0.17 | 0.15 | 0.11 |
| Dubai | 1800 | 0.20 | 0.15 | 0.13 | 0.10 |

PVTRAC (2004) also assesses the electricity costs (p. 23): "Depending on assumptions concerning economic lifetime, operation and maintenance (O&M) costs, interest rates, electricity generation per watt-peak system power, etc., the turn-key price can be translated to electricity generation costs. For the best systems available and well-chosen sites the figure of 5 €/W roughly corresponds to 0.25-0.65 €/kWh, depending on location (solar irradiation level) in the EU." It continues (p. 25): "The period until 2030 will show rapid further maturing of commercial technologies, leading to flat plate module efficiencies in the 10-25% range (35% for concentrators) and generation costs down to 0.05-0.12 €/kWh. Beyond 2030 a further reduction of generation cost is expected."

The assessment on electricity costs in RWE (2004, p. 5) is that "Taking the latter price and using a formula to calculate the PV solar electricity generating cost for a kWh, the result is 0.60 € and 0.30 € in Northern and Southern locations, respectively [RWE calculation standards], without any subsidy taken into account. With the assumed growth, it can be assumed that a similar cost reduction of 5% per year will occur in the future as will be shown later by a price experience curve for the most cost-contributing item, the solar module."

### 5.5.4 Cost development of Photovoltaics (PV) – summary

The experience curves for PVs illustrate cost reductions and a progress ratio of approximately 80% for PV modules; the studies of BOS indicate a similar progress ratio. These experience curves are based on grid-connected PV systems using modules of crystalline silicon. The bottom-up assessments have identified and quantified sources for substantial cost reduction even in the future for this technology. The most important sources of cost reductions are related to silicon cost, efficiency and scale of plants. Sources of cost reduction for thin-film modules have also been identified, however, not quantified. Nevertheless, the presented low cost target for the future does rather rely on thin-film modules than silicon modules, or a combination of them both. Moreover, it is believed that new innovative PV modules will make even further cost reductions possible.

In the NEEDS project we would like to stress the uncertainty of future cost reduction based on the differentiation in PV systems that may be. Based on incremental improvements in already existing technologies we suggest a progress ratio of 80%. To underline the uncertainty we suggest a sensitivity analysis of applying an additional lower sensitivity value of 70% and an upper sensitivity value of 85%. The lower sensitivity value of 70% represents radical improvements covering new and innovative products, processes of production and applications.

In all, the quantitative and qualitative cost reduction estimates support cost reductions illustrated by the experience curve with a progress ratio of approximately 80%. The improvements described in the literature are, however, not only incremental whereas the cost reductions may very well relate to even larger cost reductions. Cost reduction related to a progress ratio of 70 % will be more uncertain and rely on larger cost reductions and radical changes in the produce and production process. Such radical changes can also be related to the introduction of new innovative solar modules.

The studies on BOS indicate limitations in future cost reductions, and due to this the experience curve of the entire PV system may not be as huge as indicated by the PV modules. All the same, we suggest a progress ratio of 80% of PV systems in the NEEDS project – this due to the fact that the cost reductions of PV modules seems not only to rely on incremental improvements but also more radical improvement. To underline the uncertainty we suggest a sensitivity analysis of applying an additional lower sensitivity value of 70% and an upper sensitivity value of 85%.

## 5.6 Cost development of solar thermal power plants

Solar thermal power plants capture energy from solar radiation, transform it into heat, and generate electricity from the recovered heat. Over the years, four main types of solar thermal power plants have been developed:

- Parabolic trough technology
- Central receiver system
- Dish-engine system
- Solar updraft tower plant

These systems are all different and within each grouping of plants different technology concepts have been developed (see Kronshage et al., 2005). Moreover, the experience and prospects for each of the different technology concepts looks different.

The only type of power plants commercially available are the *parabolic trough plants*. These can be operated solar-only or as a hybrid system with fossil co-firing. Hybrid systems have the advantage of a high capacity factor, higher solar efficiencies and full dispatch ability of the electricity produced. In California nine parabolic trough technology power plants were built in the 1980s with a total capacity of 354 $MW_{el}$. They were all of the type “solar electricity generation systems” (SEGS) power plants and rely on natural gas to provide continuous operation when the sun does not shine (Luzzi and Lovegrove, 2004). During the early 1980s, some other small parabolic trough demonstration plants were constructed in the United States, Japan, Spain, and Australia.

In the US in April 2006 the first parabolic trough plant to be constructed in nearly two decades went online and delivered power to the grid (Saguaro Solar Power Plant in Tuscon, Arizona). The 1 MW project with turnkey costs of 6.1 million US$ was led by Solargenix Energy, a subsidiary of Spain's Acciona group. This plant is the first Concentrating solar power (CSP) plant which has been matched to an Organic Rankine Cycle Power Block. Solargenix Energy is currently building a much larger 64 MW trough of similar design outside Las Vegas in Nevada. "Thousands of megawatts of solar electric power can be brought on in the south-western United States" as proposed by an industry consultant (RenewableEnergyAssess, 2006).

An alternative parabolic trough technology power plant concept is the ISCCS (Integrated Solar Combined Cycle System). Several ISCCS projects worldwide are in the developing phase since 10-15 years, having an overall (fossil + solar) capacity of more than 1 $GW_{el}$. With the Fresnel-collector another alternative type of concentration system has been developed. The efficiency is smaller than with a classic parabolic mirror, the lower efficiency however is compensated with a lower cost. Fresnel systems are now being promoted worldwide.

The *central receiver system, the dish-engine system and the solar updraft tower plant systems* are not yet commercial. However, several demonstration plants have been developed. The largest central receiver solar system realised so far is the "Solar Two" plant in southern California, with a capacity of 10 $MW_{el}$. Parabolic dish systems are relatively small power generation units (5 to 50 $kW_{el}$), making stand-alone or other decentralised applications their most likely market (EUREC, 2004). Dish units can also be integrated to larger power production units. Currently a large-scale project is planned in California; starting at 1 $MW_{el}$, it aims at a capacity of 500 $MW_{el}$ in the long-term. Several projects of central receiver solar systems are being promoted in Spain adding up a total installed capacity of 54 MWel (PER, 2005; World Bank, 2005). In the early 1980s an experimental Solar Updraft Tower Plant with a power of 50 $kW_{el}$ was established in Spain. Currently a 200 $MW_{el}$ solar updraft tower is to be established in Australia.

As described, the experience of solar thermal power plants is limited; this due to a relative high investment cost. To commercialize the solar thermal power plants the costs need to be reduced. The question is how much and how fast costs can be reduced. In this chapter we apply the experience curve concept to estimate the size of future cost reductions. The experience curve concept is also complemented with the analysis of sources of cost reduction.

In the text we focus on cost and cost development to the extent that this is possible. However, when cost data is not always available, price data is used. In the early phase of commercialisation it is difficult to define the relation between cost and price. The price can be higher than the cost covering past and future research and development costs; the price can also be lower than the actual cost to boost the market.

### 5.6.1 Cost development of solar thermal power plants – experience curves

Solar thermal power plants have been implemented since the 1980s, however only a few studies have approached experience curves to analyse the future cost reduction trends. One of the reasons is the relatively few power plants build. As has been described above, only parabolic trough plants SEGS systems can be considered commercial. Other systems are demonstration plants.

Enermodal 1999 uses data of installed capital costs for SEGS plants in California (SEGS I to SEGS IX) and develop an experience curve for these plants with a progress ratio of 88%. Since only three doublings in capacity have been produced the authors proposes to use a range of progress ratios of 85-92 % for parabolic trough as well as for central receiver this due to the many similarities of the two systems, see Figure 5.8.

Several studies present estimated experience curves, i.e. they do not present any actual experience curves but rather apply the concept of experience curves and an assumed progress ratio or range of progress ratio. Foe example, in the Athene model progress ratios are used to estimate future cost; the progress ratio has been applied for subsystems, i.e. collectors (90%) storage (88%) and electrical power block's (94%) (see DRL, 2004).

In Spain it is assumed that during the Plan des Energías Renovables period (PER, 2005-2010) within which 500 MW of solar thermal power plants will be built the operation and investment cost would decline by 20%. Compared with the already installed capacity of 354 MWel in the US, this would mean a doubling of capacity and therefore a progress ratio of 80%.

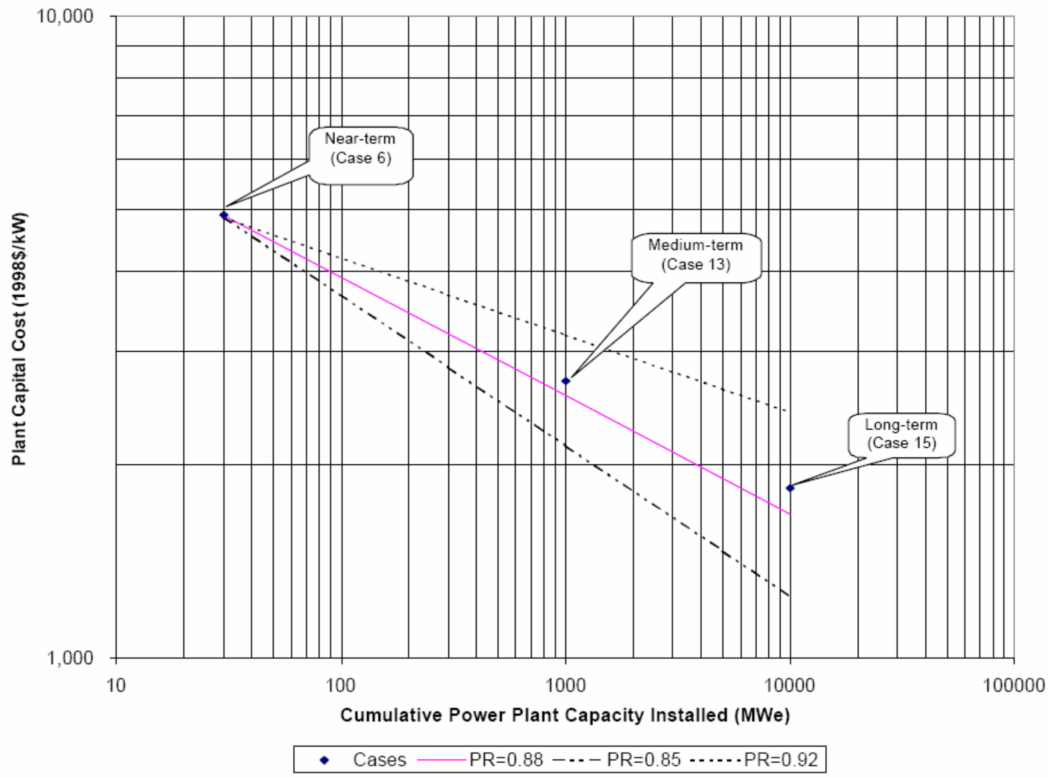


Figure 5.8. The extrapolated experience curve of central receiver (Enermodal, 1999).

### 5.6.2 Cost development of solar thermal power plants – bottom-up assessments

Solar thermal power plants will develop over time, and the focus will to a large extent be on cutting costs. The development may very well lead to a concentration to one or a few technology concepts. Even so, there will probably be different technologies for different regions. In the following text we describe studies of bottom-up assessments for different solar thermal power plants. In general many studies present cost reductions of solar thermal power plants (see for example IEA, 2001; Leitner and Owens, 2003; Greenpeace, 2004; DRL, 2004; DRL, 2005).

*Parabolic trough plants* will most likely be scaled-up and have a power units of 150 – 400 $MW_e$ in a ten years time, and most probably a large variety of technological concepts will be developed in parallel, see (Kronshage et al., 2005). In most cases, hybrid parabolic trough plants with fossil co-firing will be preferred, which are economically advantageous. However, support design like current feed-in laws in Spain, may support the development of solar-only plants.

Several studies have been developed that discuss the cost development of parabolic trough plants (see for example Pilkington, 1996; Price and Kearney, 1999; Enermodl, 1999; Morse, 2000; Becker et al., 2000; Leitner, 2002; Price and Kearney, 2003; Sargent and Lundy, 2003; Schwer and Riddel, 2004; ECOSTAR, 2005). The studies identify and describe technology development options and paths and cost reduction related to these development paths. In the near term, investment cost is seen to be reduced to approximately 2400-3500 euro/kW and the levelised electricity cost is seen to be reduced to approximately 7-10 eurocent/kWh; these figures refer to cost reductions up to 50% or even more.

The most up to date source of data on expected cost reductions is the ECOSTAR study (ECOSTAR, 2005) This study provides data on electricity costs of some current reference CSP technologies and identify the essential technology innovations that may contribute to reduce costs. In all, the sources of cost reductions are many and to be considered incremental.

- In the case of parabolic troughs with thermal oil the reduction of the levelised electricity (LEC) cost is estimated to 13-29% in the near term. The most effective measures are those impacting concentrator and storage costs.

- In the case of Parabolic troughs with direct steam generation the reduction of the levelised electricity (LEC) cost is estimated to 23-38% in the near term. The most significant improvement is due to the increase of the unit size of the power block.

- In the case of Parabolic troughs with the linear Fresnel system the reduction of the levelised electricity (LEC) cost is estimated to 3-20% in the near term. It appears not clear whether Linear Fresnel Systems will be able to contribute substantially to the costs reduction of CSP systems.

In all, the figures of costs reductions described above do not include effects of volume production or scaling of the size of the plants beyond 50 MW unit size, which would result in further cost reductions. Based on the results of the Sargent and Lundy study, the authors assume that a 14% cost reduction can be obtained from larger power blocks (400 MW) and 17% cost reduction from volume production effects. The authors conclude that in the next 15 years an overall cost reduction of 55 - 65% can be estimated.

*Central Receiver systems (CRS)* will probably develop as demonstration projects for some years and the development and optimisation of thermal storage concepts will continue. The idea of multiple tower plants might be reconsidered in order to be able to build larger plants. The cost level reached by CRS will depend on how this concept will look like. Several studies have also been developed that discuss the cost development of central receiver systems (see for example Enermodal 1999, Becker et al., 2000; Sargent and Lundy, 2003; ECOSTAR, 2005).

Similar to the parabolic trough systems the ECOSTAR study provides data on electricity costs and innovations of central receiver systems. Also for these technologies the sources of cost reduction are many and each source of cost reduction to be considered incremental.

- In the case of CRS using molten salt as heat transfer fluid the reduction of the LEC is estimated to 11-25% in the near term. From a sensitivity analysis on innovations it can be concluded that molten salt central receiver technology is strongly influenced by the size of the heat storage. After the large area heliostats, the second most important factor is increasing the number of operating hours to 24 h.

- In the case of CRS using saturated steam as heat transfer fluid the reduction of the LEC is estimated to 21-32% in the near term. The challenges to improve this technology are significant because the problem of superheated steam receivers is not solved today. The steam concept does not present any intrinsic benefits compared to the parabolic trough/Fresnel approach that may justify the higher effort of a two-dimensional concentration.

- In the case of CCRS using atmospheric air as heat transfer fluid the reduction of LEC is estimated to 25-37% in the near term. Essential further improvements are necessary to achieve similar cost figures than the other technologies presented here. Improvements should focus on the receiver performance, on the integration into a larger power block and on a reduction of the storage costs.

- In the case of the reduction of LEC is estimated to 17-28% in the near term. A larger module size shows the largest impact on the LEC. Lower investment in conjunction with higher performance leads to benefits both for the solar and the fossil operation. The integration of a solar receiver into a larger gas turbine system is a big challenge and associated with high uncertainties and risks. However, in this concept it is an essential step to reduce the cost significantly.

As mentioned for the parabolic trough systems, these figures of cost reductions do not include effects of volume production or scaling of the size of the plants beyond 50 MW unit size. Assuming similar figures also for the central receiver systems, an overall cost reduction of 55 - 65% can be estimated in the next 15 years.

*Solar updraft tower plants* are less advanced than the other types of solar thermal power plants and a future development of a “low-tech” approach will probably result in lower costs of electricity. Volume effects and scale-up will further bring down costs. A 24 hour operation could be gained by a storage design. Self cleaning foils, roof or chimney construction will realise further cost reduction.

Economic appraisals based on experience and knowledge gathered so far have shown that large scale solar updraft towers are capable of generating electricity at costs comparable to those of conventional power plants. For a 100 MW towers costs of 4-16 eurocent/kWhel have been calculated, depending on different discount rates. (dos Santos Bernardes, 2004). Other cost estimations were made in the context of the 200 $MW_{el}$ solar updraft power plant intended in Australia. With a scale-up to 200 $MW_{el}$ costs of electricity of 8 ct/kWh for a plant without storage and about 6 ct/kWh for a plant with storage are projected (Schlaich et al. 2005). With their tremendous land demand solar updraft power stations will only spread in the unpopulated, large desert regions.

*In all*, the ECOSTAR study comes to the conclusion that in southern Spain cost of electricity of around 6 ct/kWh could be achieved until 2020 for concentrating solar power (CSP) technologies, going down to 4.5 ct/kWh in high insulation areas. Sargent & Lundy state that cost of concentrating solar power (CSP) could be expected to fall down to a level from 3.5-6.2 ct/kWh within the next 20 years (Sargent and Lundy, 2003).

One of the main sources of cost reduction of solar power plants is the up-scaling of the plant unit size. According to the Sargent and Lundy study (2003), to achieve a cost reduction of 14 % a scale-up of the power block units to 400 $MW_e$ is necessary for parabolic trough plants. The S&L scenarios assume a first 400 $MW_e$ parabolic trough plant in 2020, even in the more pessimistic expansion scenarios. The Athene study (DLR, 2004) assumes capacity units beyond 400 $MW_e$ at an overall capacity worldwide of about 42 $GW_{el}$ and beyond (assumed for 2023).

Another important source of cost reduction will be mass production. The Sargent and Lundy study (2003) says a deployment rate of 600 $MW_e$ per year for parabolic trough technology is necessary to achieve a cost reduction of 17 % in the next 15 years. This would lead to a capacity of about 9 $GW_{el}$ until 2020. This increase in installed capacity is supported by several scenarios (see for example DRL, 2005 and Greenpeace, 2004).

*In a longer term and reaching 2050,* the cost development target for solar thermal power is 4-5 ct/kWh for base load, 5-8 ct/kWh for mid-load and more than 10 ct/kWh for peak load (DLR 2005). A broad variety of assumptions determines the resulting electricity costs. The most important determinant is the assumed development of the specific investment costs for new plants. The MED-CSP study assumes specific investment costs of 3,100 $/kW in 2000, 4,700 $/KW in 2020 and 4,100 $/KW in 2050 for parabolic trough plants (DLR 2005). The time lag in cost reduction will be due to the need of thermal storage and enlarged solar fields to gain a higher solar share. The need of thermal storage will result in higher investment cost but at the same time improve the capacity factor; which in turn will reduce electricity costs.

### 5.6.3 Cost development of solar thermal power plants – summary

In all, the solar thermal power plants have been developed since the 1980s, however, only a few plants have been build. The experience curve studies of these initial solar thermal power plants indicate cost reduction. In the NEEDS project we suggest the use of an experience curve with a progress ratio of 88%. To underline the uncertainty of the cost reduction we suggest sensitivity analyses applying an additional lower sensitivity value of 83% and an upper sensitivity value of 93%.

The bottom-up assessments presented above provide estimates of future cost reductions and important areas in which cost reductions are needed. These estimates of cost reductions strongly support further incremental development paths of cost reduction. The impact of each individual development is small but all together they show a considerable decrease in potential reduction of investment cot and LEC. Based on the bottom-up study of sources of cost reduction a progress ratio of 88% seems relevant. However, the study also underline the huge uncertainty of the cost reduction and the need for a sensitivity analysis applying an additional lower sensitivity value of 83% and an upper sensitivity value of 93%.

## 5.7 Cost development of bio-energy technologies

Since the first utilisation of fire, biomass has been used by mankind for generating heat and power. Additional to the traditional bio-energy technologies like wood stoves and fireplaces in homes for heating and cooking, new technologies have been developed, among others industrial-sized power plants and heating plants, but also combined heat and power (CHP) plants. Also, the range of bio-energy sources used has been enlarged including energy wood grown explicitly for energy purposes, residual wood from forests, industry, and households, and herbaceous matter such as straw, perennial grasses, and cereals.

In the NEEDS project not all technologies or bio-energy resources are included. The bio-energy systems included are:

- Short-rotation poplar in a boiler with steam turbine and CHP
- Residual wheat straw in a boiler with steam turbine and CHP
- Short-rotation poplar in a high-efficiency gasifier with gas engine and CHP
- Residual forest wood in a high-efficiency gasifier with gas engine and CHP
- Short-rotation poplar in a high-efficiency gasifier with fuel cell and CHP (future option)
- Residual forest wood in a high-efficiency gasifier with fuel cell and CHP (future option)

### 5.7.1 Cost development of bio-energy technologies – experience curves

A few experience curve studies describing cost development of bio-energy technologies have been found. The experience curve by Junginger et al. (2005) describes cost reduction in the wood-fuel supply chain, or primary forest fuel (PFF). The experience curve, with a progress ratio of 85%, is based on production cost data of different types of supply chains (terrain, roadside and terminal). The sources of the data are not presented in the publication.

In Junginger et al., (2004c) experience curves for CHP combustion plants are presented. The progress ratio of the experience curves for CHP investment cost was estimated to 75%, assuming an initial cumulative capacity of 102.5 MW, and 91%, assuming zero initial capacity. However, in both cases the distribution of the cost data was too high to indicate any progress ratio of relevance. The authors also present a progress ratio for biomass CHP electricity generation of 95%. The figures used were based on actual electricity production per plant, O&M cost based on literature and expert opinions, average wood-fuel prices from literature, and the allocation of electricity and heat based on the annual economic value of both products – i.e. the experience curve is not based on any actual cost data but on an estimated cost.

In OECD/IEA (2000) an experience curve for electricity from biomass in presented – based on data from the EU-ATLAS project. The progress ratio of the experience curves is estimated to approximately 85%. However, it is not clear what type of data that has been used. Furthermore, it is not clear what type of biomass sources and technologies that are included.

Estimated progress ratios for bio-energy systems of 83-97% have been presented by Ökoinstitut (2004) – these figures are, however, not based on any actual cost data.

*Comments*
The biomass system is complex and covers many types of combinations of conversion technologies and fuel supply chains. Experience curves have only been developed for a few systems and these curves have been based on a broad set of data. The bio energy systems, - however, not always the individual technologies - are immature and it is difficult to know what will be in the future. For this reason, future cost development is uncertain.

### 5.7.2 Cost development of bio-energy technologies – bottom-up assessments

The cost of bioenergy will depend on both the bio-energy feedstock and on the conversion technologies. The development of different types of feedstock and systems for production of feedstock indicate cost reductions. One example is the cost of willow that could be reduced as a result of scale effects, new planting and cultivation technologies, higher yielding clones and less transport. Rosenqvist et al. (2005) estimate a cost reduction of 35% based on the above-mentioned sources of cost reduction. Anther example is the cost of logging residues that could be reduced considerable. The sources of cost reduction would be improved technology refinement of procurement logistics and administration; new concepts of logging residue harvest and transport; increase in scale and reduced transportation distances; logistics and further technology development. By introducing bailing of logging residues to compact raw material and improve the productivity of long-distance transport, the cost could be reduced, on average, by 20 to 30% (Glöde, 2000).

Focusing on the conversion technologies the net investments vary significantly within the costs groups:

- Construction technology,
- Mechanical technology and
- Electro and control systems

Varieties (e.g. load changes, operational hours, local conditions) lead to broad differences in the plants design and therefore in its costs structure. Due to this uncertainty the costs given in this study only represent an order of magnitude. In certain cases considerable lower or higher costs might be achieved.

*Construction Technology of Energy Conversion Techniques.* Generally the costs for construction technology of a biomass plant contain expenses for structural measures such as a vessel- and machine house or fuel storage. For plants over 100 $kW_{th}$ these costs sum up to about 20-40 % of the total investment costs in new buildings, while for existing buildings the construction costs are significantly lower. There tends to be no cost reduction potential in this sector.

*Mechanical Technology of Energy Conversion Techniques.* This group of costs contains all mechanical components including conveyer systems for biomass. These can be classified into the following essential plant components:

- Biomass vessel including feeding, ash discharge and ash storage
- Flue gas cleaning devices
- Mechanical technology of biomass storage, -conveying and –feeding
- Water treatment devices
- Flue gas and air system (incl. ventilation)
- Steam turboset and/or gas turbine including the generator
- Connecting pipelines with pumps, container (e.g. feeding water tank) and armatures

The costs for biomass vessels strongly depend on the capacity and on the type of device. The type of fuel also has an influence on the costs. Combustion vessels for crops, for example, have 10-50 % higher costs than comparable wood vessels with identical size. Vessels with a thermal capacity over 100 kW are generally offered with an automatic fuel feed-in and are equipped with downstream dust separation equipment. Yet the specific costs do not decrease for larger plants, which are mainly caused by the necessary extensive systems engineering for plants with more than 1 MW. Such plants are equipped with an automatic ash removal and are partly designed as grate-stoker furnace, which lead to higher costs compared to other types such as an underfeed furnace. Currently there is a vital development in the field of gasification. The complex dust removal for plants with thermal firing capacity over 5 MW (mainly with electro- or fabric filter instead of/or additionally to the multi cyclone) increases the costs significantly. Furthermore, the steam of larger plants is often used for heat production (process heat or district heat) which leads to higher costs compared to simple hot water production.

Depending on the requirements concerning the rest dust concentration of the flue gas there are options for using different dust removal devices. Multi cyclones are the most economic dust removal systems, but they are only used in plants smaller than 5 MW because of their comparably high rest dust concentration. In plants below 5 MW there are no prescriptive limits for dust concentration.

Behind the biomass vessel the most expensive component in a combined heat and power plant is the steam turbine and/or the gas turbine. The slower decrease of the specific costs for plants above about 1 MW is mainly caused by the fact that for larger capacities extraction condensing turbines are used instead of extraction back-pressure turbines. Furthermore, larger turbines are multi-stage machines (instead of single-stage machines) that have higher costs but also higher efficiencies. Over the last years the research and development activities in this sector have generally been very modest because efficiency improvements could be achieved mainly due to an increase of the steam inflow parameters (pressure and temperature). Respective parameters are not achievable in the smaller range of performance (firing thermal capacity below 100 MW).

*Electro- and Control systems for Energy Conversion Techniques.* The costs for electro and control technologies are mainly affected by the entire electro-technical coupling of plant and machinery systems. Furthermore, this group of costs contains the superior control and communication system while the technique of measurement and control for single components are usually included in the delivery of the component supplier and belong to the group of costs for the mechanical technologies. The costs for electro- and control systems strongly depend on the size and complexity of the plant, the desired degree of automation and the respective boundary conditions, such as the existing electro technical infrastructure. Hence the indication of specific values for these costs is associated with high uncertainties. The costs for electro- and control systems are approx. 10 to 20 % of the costs for mechanical technologies.

*In addition to the investment cost of the* conversion technologies the *operational costs needs to be included.* This group of costs contains all expenses for maintenance-, repairing- or servicing-measures, personal costs for the internal company's staff and expenditures for taxes and insurances. For an estimate of costs these expenditures can be set over the plants overall life time and are defined as a share of the investment costs. Experience values are listed below:

- Construction technology of the energy conversion 0.5-1.0 %/a of investment costs,
- Mechanical technology of energy conversion 2.0 %/a of investment costs,
- Electro- and Control systems 1.0-1.5 %/a of investment costs.

The costs for insurances consist of expenditures for liability-, machine- and other insurances (insurance for natural hazard etc.). These costs sum up to about 0.5- 1 %/a of the investment costs.

Based on these assumptions the costs development has been presented in table 5.9.

**Table 5.9. Cost Development of Biomass Technologies for Electricity Generation** (Data developed by Institut für Energiewirtschaft und Rationelle Energieanwendung (IER), Germany)

| | | Extraction Condensing Turbine | | | Extraction Condensing Turbine | | | Wood gasification Combined Cycle | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Straw | | | Wood Chips | | | Wood Chips | | |
| | | Today | 2025 | 2035 | Today | 2025 | 2035 | Today | 2025 | 2035 |
| **Max. Net El. Power** | **[MW]** | 20 | 20 | 20 | 20 | 20 | 20 | 8 | 15 | 20 |
| **Net El. Power at El. Peak Load** | **[MW]** | 20 | 20 | 20 | 20 | 20 | 20 | 8 | 15 | 20 |
| **Net Thermal Power at Thermal Peak Load** | **[MW]** | 61 | 61 | 61 | 35 | 35 | 35 | 8 | 14 | 18 |
| **El. Efficiency at Thermal Peak Load** | **[%]** | 21 | 21 | 21 | 31 | 31 | 31 | 36 | 38 | 40 |
| **Thermal Efficiency at Thermal Peak Load** | **[%]** | 64 | 64 | 64 | 54 | 54 | 54 | 36 | 36 | 36 |
| **Technical Life Time** | **[a]** | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| **Spec. Investment Costs (Overnight Capital Costs)** | **[€/kW$_{el}$]** | 2600 | 2200 | 2200 | 1750 | 1600 | 1600 | 2150 | 1900 | 1800 |
| **Fixed Costs of Operation** | **[€/kW$_{el}$/yr]** | 106,6 | 106,6 | 106,6 | 71,75 | 71,75 | 71,75 | 161,25 | 123,5 | 90 |

### 5.7.2 Cost development of bio-energy technologies – summary

Sources of cost reduction for different types of bio-energy technologies indicate smaller or larger cost reductions in the future. Smaller cost reductions will be expected for well established technologies and larger cost reductions may be achievable for new innovative technologies. The uncertainty is, however, huge.

In the NEEDS project very rough estimates are used to illustrate future cost development. For the production of bio-fuels (wood chips etc.), a progress ratio of 85% is used (c.f. Junginger et al., 2005). To underline the uncertainty we suggest a lower sensitivity value of 80% and an upper sensitivity value of 90%. For conversion technologies a progress ratio of 95% is suggested; the assumption is based on the progress ratio of advanced fossil fuel technologies and coal related technologies (see chapter 5.1). To underline the uncertainty we suggest a lower sensitivity value of 90% and an upper sensitivity value of 100%.

## 5.8 Cost development of hydrogen technologies and hydrogen production

In the sections 5.1-5.7 cost development of energy technologies for the generation of electricity has been discussed; Electricity which will be a very important energy carrier for the future. Another vital energy carrier for the future may be hydrogen that can be produced from either renewable or fossil energy sources.

The hydrogen production technologies cover natural gas steam reforming, heavy oil partial oxidation, coal gasification and electrolysis. Today the most inexpensive way to produce hydrogen is through steam reforming of natural gas; it is therefore also the most common production process. Electrolysis, a process that splits pure water with electricity, have the largest environmental benefits, if electricity is generated in a sustainable way, and is thus a very interesting option for the future. Three types of industrial electrolysis units are being produced today; unipolar or bipolar alkaline electrolyses and solid polymer electrolyte (SPE) (see Mack, 2005). However, the cost of producing hydrogen through electrolysis is high and today only 4% of the hydrogen is produced in this way (Sigurvinsson, 2005). To increase the share of hydrogen produced through electrolysis costs need to be reduced.

Krewitt and Schmid (2004b) present historical cost data for different hydrogen production technologies; natural gas steam reforming, heavy oil partial oxidation, coal gasification and electrolysis, see figure 5.9. The cost data do not origin from the same sources but different sources. Based on this data and data for cumulative installed capacity experience curves for the different technologies has been developed; however, no progress ratio has been presented. Reductions in investment cost can be identified for electrolysis and heavy fuel partial oxidation. Cost development of natural gas steam reforming has been nearly constant and for and coal gasification slightly increasing. Furthermore, Krewitt and Schmid (2004b) indicate that no cost data is available for the analysis of hydrogen storage options and hydrogen delivery infrastructure (pipelines, filling stations).[15]

The study by Krewitt and Schmid (2004b) indicate initial cost reductions for the production process of hydrogen through electrolysis by approximately 40%. A study by Sigurvinsson

[15] Rogner (1998) do not present any actual experience curves but assume progress ratios for hydrogen related technologies and processes. For hydrogen production via electrolysis Rogner propose progress ratios of 80%, 85% and 90%.

(2005) focused on cost development of hydrogen production through electrolysis present an analysis of sources of cost of the electrolysis process. The study show that smaller plants have much higher production cost than larger production units. Moreover, the study show that the maintenance cost is a much larger part of production cost for the smaller plants than for larger plants. An important result of the study is that it shows that electricity cost is about 60% of the production cost in a larger plant. Sigurvinsson (2005) illustrate that the production hydrogen through electrolysis varies widely, form 1.6 and 4.15 €/kg$H_2$. The variety in cost depends on assumptions made regarding discount rate, currency exchange rates and a stable electricity price. In all, Sigurvinsson is claiming that cost development of hydrogen produced through electrolysis will to a large extent depend on the cost development of electricity.

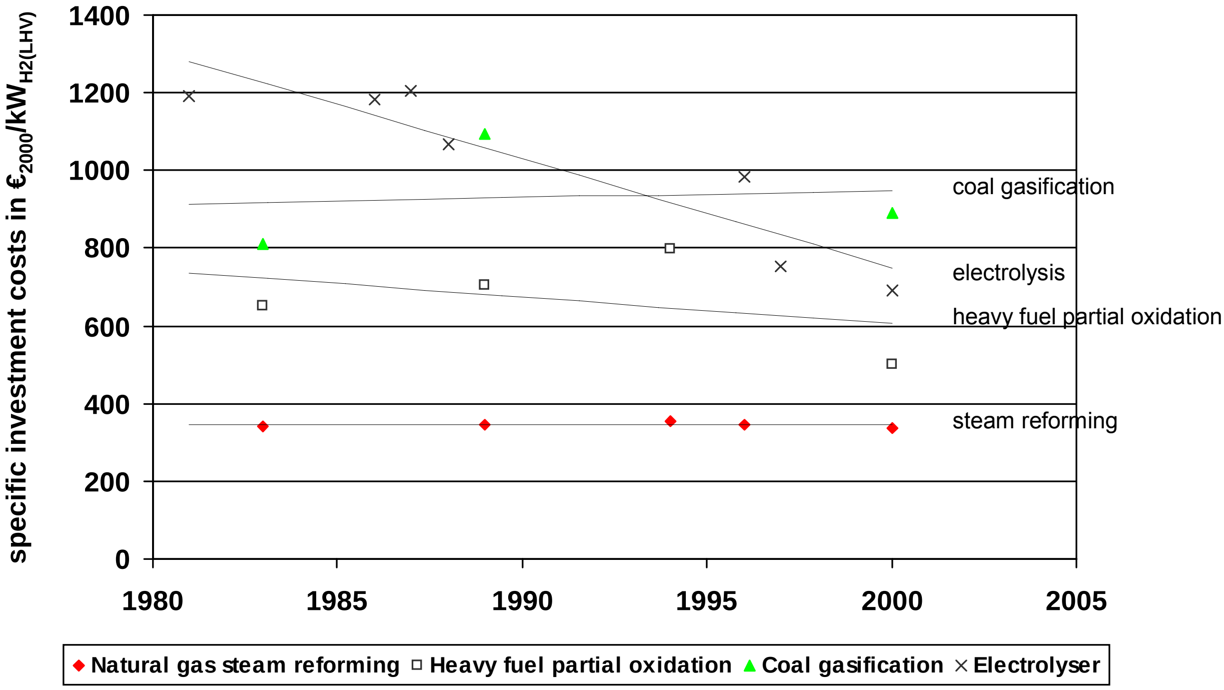


Figure 5.9 Development of specific investment costs over time for different hydrogen production technologies Krewitt and Schmid (2004b).

In all, the hydrogen technologies are immature and it is unknown what technologies will be in the future. For this reason the future cost development is uncertain. The initial experience curve studies on hydrogen production technologies indicate cost reduction as well as cost increase. In the case of hydrogen production through electrolysis initial cost reductions have been illustrated. However, this cost development of this process will to a large extent depend on the future cost development of electricity.

# 6. Conclusions – recommended experience curves

Based on the results of this report we present the cost development paths and the experience curves of the selected energy technologies as described in Table 6.1. The figures presented are based on a critical review of experience curves presented in the literature, a complementing bottom-up analysis and for some technologies an additional long-term expert assessment.

Table 6.1 Experience curves for new energy technologies generating electricity

| **Technologies** | **Progress ratio (%)** | **Sensitivity range (%)** |
|---|---|---|
| Advance fossil fuel technologies<br>- coal related technologies<br>- fossil gas related technologies (€/kW)<br>- oil related technologies (€/kW)<br>- $CO_2$ capture and sequestration (€/kW) | <br>95<br>90<br>100<br>100 | <br>93-97<br>85-95<br>-<br>- |
| Advanced nuclear (€/kW) | 100 | 95-105 |
| Fuel cells (€/kW) | 80 | 75-90 |
| Wind turbines (on – and off-shore) (€/kW)<br>- electricity less windy areas (c€/kWh)<br>- electricity more windy areas (c€/kWh) | 90<br>85<br>80 | 88-92 |
| Photovoltaics (PV)<br>- electricity | 80<br>80 | 70-85<br>70-85 |
| Solar thermal power plants (CSP) | 88 | 83-93 |
| *Biomass energy technologies (first draft)*<br>*- biofuel production (wood chips, SRF)*<br>*- conversion technologies (c.f. coal)* | <br>*85*<br>*95* | <br>*80-90*<br>*90-100* |

The result of the critical review of the experience curves studies and the bottom-up analysis agree in most cases, i.e. cost reductions illustrated by the experience curves are found as corresponding incremental cost reduction described in the bottom-up analysis. Only one exception is found; in the case of nuclear the extrapolation of the experience curve illustrates a cost increase whereas the bottom-up approach illustrates a cost stabilisation. We suggest the use of a stabilised cost in the NEEDS project.

For some technologies, the bottom-up analysis confirms large uncertainties in future cost development not captured by the extrapolation of the experience curve. To underline the uncertainty of the cost reduction of these technologies (advanced nuclear, fuel cells, photovoltaics and solar thermal plants) we suggest a sensitivity range of the progress ratio of, at least, +/- 5%. For other technologies we suggest a sensitivity range of +/- 2%. The sensitivity values could be used in the NEEDS project for the development of specific scenarios. For example, in a scenario focused on renewable energy much focus will be on technologies such as the PVs. This in turn, will lead to the diffusion of PVs but also the possibility of the diffusion of new types of PVs facilitating faster cost reductions. The same argument could be used for advanced nuclear and the introduction of a fourth generation in a nuclear focused scenario.

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