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# COST MODELS FOR CURRENT AND FUTURE HYDROGEN PRODUCTION

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The European Commission is supporting the Coordination Action "HyLights" and the Integrated Project "Roads2HyCom" in the field of Hydrogen and Fuel Cells. The two projects support the Commission in the monitoring and coordination of ongoing activities of the HFP, and provide input to the HFP for the planning and preparation of future research and demonstration activities within an integrated EU strategy.

The two projects are complementary and are working in close coordination. HyLights focuses on the preparation of the large scale demonstration for transport applications, while Roads2HyCom focuses on identifying opportunities for research activities relative to the needs of industrial stakeholders and Hydrogen Communities that could contribute to the early adoption of hydrogen as a universal energy vector.

Further information on the projects and their partners is available on the project web-sites www.roads2hy.com and www.hylights.org

# COST MODELS FOR CURRENT AND FUTURE HYDROGEN PRODUCTION

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# 1. Introduction

This report is a deliverable of the Roads2HyCom project, a partnership of 29 stakeholder organisations supported by the European Commission Framework Six programme. The project is studying technical and socio-economic issues associated with the use of Fuel Cells and Hydrogen in a sustainable energy economy. Within the project, several studies have been made related to the question of primary energy sources to produce Hydrogen, covering their potential, linking and interconnectivity, and cost. This report looks in detail at cost models for the production of Hydrogen.

One potential hurdle in the widespread uptake of hydrogen in today's technologies is the cost of hydrogen. In particular, "green" hydrogen, which is produced from renewable energies, today still has a significantly higher production cost than hydrogen produced from natural gas through steam methane reforming (SMR).

In order to identify the potential for lowering the cost of hydrogen supply and to allow for projections of the development of future hydrogen costs, it is necessary to understand the composition of today´s production costs. Specific steps in the production process or expensive distribution procedures could constitute bottlenecks in reducing hydrogen prices. Only if hurdles are identified they can be tackled and their influence minimised. Furthermore, the impact of feedstock prices (electricity, gases etc.) on production cost is important information to be integrated into future cost projections, especially for fossil fuel derived hydrogen. Details on the cost-structure are necessary in assessing the supply price for a specific location, depending, for instance, on the type of distribution transport. In future scenarios tube-trailer transport could be replaced by pipelines, depending on the total demand, which would dramatically reduce transport cost to a specific location. The extrapolated price could have an important influence on the decision on whether applications in a given location will be economically feasible and under which conditions. In order to prepare the necessary data, though, the detailed structure information of the cost of delivered hydrogen is a prerequisite.

This report therefore establishes cost-models for current and selected future methods of hydrogen production. Selection of the latter was based upon technological viability and likelihood of market introduction for the time horizon up to the year 2020 (see also [Nygaard 2008]).

It has to be stressed, though, that the main focus of this report is the establishment of the calculation 'models' (as described in the tables, based on spread sheets). Any element of these models can be modified separately in order to adapt the results to changes in boundary conditions and parameters. The target of the analysis shown here is <u>not</u> to calculate actual prices, but to establish the procedure for calculating these. Nevertheless, a comparison has been made with Roads2HyCom Deliverable 4.3 (Report R2H4003PU) [Prieur 2008] in which hydrogen prices from US-reports have been verified. No contradictions between the methodologies were found.

# 2. Methodology

## 2.1 General approach

The general approach of the cost model analysis can be seen in Figure 1. Various processes are depicted here, some of which are already state-of-the-art and some not yet realised at a commercial scale but regarded as probable pathways of hydrogen production (cf. also [Nygaard 2008]). These processes can be divided into direct hydrogen producing, electricity producing, and syn-gas producing processes. Direct processes produce hydrogen in the first conversion step. Electricity producing processes need a subsequent electrolysis in which water is split into hydrogen and oxygen. In syn-gas (synthesis gas) producing processes a gas mixture with varying amounts of carbon monoxide and hydrogen is formed. Through reforming and/or shift reactions, with or without carbon capture and sequestration (CCS) technologies, the yield of hydrogen is increased to a commercially viable level.

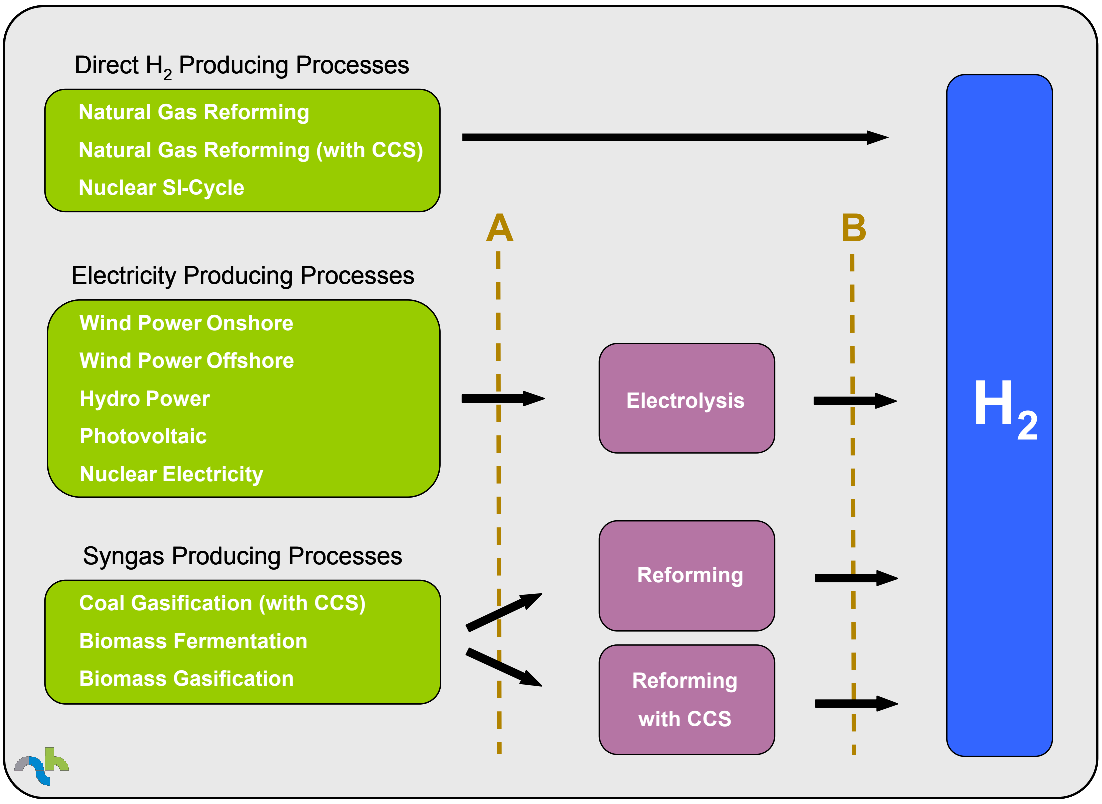


**Figure 1: Schematic overview of available cost models**

**A modular structure allows for later changes, if single steps of the entire chain of costs have to be modified.**

For a better understanding of this modular approach two system interfaces have been inserted into the model (A and B). These interfaces, of course, are only applicable to the electricity and the syn-gas producing processes, allowing a separate view on the costs before and after the second conversion step. It also means that if a technological breakthrough for one application occurs, for instance electrolysis, this will reduce the cost of this conversion step significantly, but without impacting on the following process steps, for instance delivery. The cost of hydrogen estimated from the cost model, though, can easily be adapted to this new development by adjusting only the specific building block in the production chain calculations. This procedure has been introduced in detail in [Linnemann 2007].

It has to be noted, that the 'models' presented here are representative of the calculation scheme. The tables shown in this report use 'typical' values, but in no way attempt to deliver actual predictions of current or future hydrogen prices.

## 2.2 Basic Assumptions and Calculation Layout

The assumptions for the economic boundary conditions refer to the same conditions for all processes analysed here, as far as applicable. The interest rate was chosen between 7 and 9% p.a. and the depreciation set to 10-15 years. Two exceptions were made with the depreciation of the biomass fermentation plant (25 years) and the coal and nuclear fired plant (50 years). The other conditions, as natural gas (NG) costs, electricity costs, feed water costs, export steam price, cooling water, nitrogen costs, labour costs, etc., are not relevant to all of the processes.

The calculation in most of the cases begins with the allocation of "land and fencing" (Table 1). This includes all cost of land use, including buildings. It is divided into built area (baseplate), the total land use and fencing. The following table (Table 2) shows the calculation of 'capital expenditure' which is derived from information on the component itself, the quantity, units, the price per unit and delivers the total price (investment in equipment).

**Table 1: Allocation of land and fence**

| | Area (baseplate) | Proportion land | Proportion fence |
|---|---|---|---|
| Component 1 | 150,00 m² | 1.500,00 | 120,00 |
| Component 2 | 100,00 m² | 1.000,00 | 80,00 |
| Component 3 | X m² | =2500/250*X | =200/250*X |
| **Area to be allocated** | | | |
| Baseplates (sealed area, concrete)) | 250,00 m² | *2.500,00 m²* | *200,00 m* |
| Land in total | 2.500,00 m² | | |
| Fence incl. gate | 200,00 m² | | |
| | | | |

**Table 2: Calculation of capital expenditure**

| Component | Quantity | Unit | Price/Unit | Total |
|---|---|---|---|---|
| Component 1 | 1,00 | plant | 2.500.000,00 € | 2.500.000 € |
| Component 2 | 5,00 | unit | 230.000,00 € | 1.150.000 € |
| Component 3 | 2,00 | stations | 425.000,00 € | 850.000 € |
| | | | | |
| **Subtotal** | | | | 4.500.000 € |
| | | | | |
| Project planning costs | 5,56 | % | | 250.000 € |
| | | | | |
| **Capital expenditure I** | | | | 4.750.000 € |

The cost of the ‘provision of energy’ (Table 3) has five columns. The first gives information about five sections, namely the economic boundary conditions, the specific consumption of media, the basic data for the annual costs and the specific costs per unit of hydrogen delivered from the process step.

The economic boundary conditions state all information about the interest rate, depreciation period, the annuity factor and the costs per unit of different inputs of each plant. The section ‘specific consumption’ includes the required inputs (e.g. electricity or cooling water) per ton of hydrogen production. The section ‘basic data’ includes the capacity factor and the power input to the plant. With this information the total annual input and the hydrogen production will be calculated. The only cost data in this section is the capital expenditure, which is transferred from Table 2. In the ‘annual costs’ section the total annual costs will be calculated. For this the annuity is carried over and all input costs are calculated by multiplying the data of the economic boundary conditions with the basic data. The last section is the specific costs for further calculations. It includes the costs of hydrogen production in different units (€/Nm³, €/kWh, €/t $H_2$) for carry-over into a subsequent step of processing.

The second column defines the abbreviation for all the data, the third gives the formula for the values calculated, the fourth reflects the numerical value and the last one states the unit.

**Table 3: Costs for the provision of energy**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| | | | | |
| | | | | |
| | | | | |
| **Specific Consumption** | | | | |
| | | | | |
| | | | | |
| | | | | |
| **Basic data** | | | | |
| | | | | |
| | | | | |
| | | | | |
| **Annual costs** | | | | |
| | | | | |
| | | | | |
| | | | | |
| **Specific costs** | | | | |
| | | | | |
| | | | | |
| | | | | |

For performing the calculations, the tables are implemented in Excel. Sensitivity analyses of the influence of single parameters can easily be obtained by varying the respective value in the tables and recording the changes in hydrogen cost. Several steps of processing, for instance production, delivery, processing etc., can be chained by carrying over the value from the previous step into the input category of the subsequent processing procedure. In this way the impact of the single steps within the chains indicated in Figure 1 can be logically separated.

The procedure is explained in some detail for the natural gas reformer case (Section 3.1.1), after which the tables should explain themselves. Comments are offered in those cases where technologies introduce specific aspects not covered in the first case.

# 3. Cost Models

## 3.1 Direct Hydrogen Producing Processes

Direct processes produce hydrogen within a single conversion step. This applies for instance to Natural Gas Reforming, where natural gas is directly reformed to hydrogen.

It has to be noted, that the 'Direct Hydrogen Producing Process models' presented here are representative of the calculation scheme. They use 'typical' values in the tables, but in no way show predictions of actual or future hydrogen prices.

### 3.1.1 Natural Gas Reforming

The natural gas reforming process produces hydrogen by passing natural gas over a nickel or copper catalyst together with steam at around 600°C. The process is endothermic and requires heat. The product gas is a mixture of hydrogen and carbon monoxide that has to be refined in a shift reactor, where the carbon monoxide is converted to hydrogen and carbon dioxide adding more steam. Hydrogen is then separated out of the resulting gas stream at the required purity. The process described here includes all of these steps.

This section describes the costs of a Natural Gas Reformer plant with a capacity of 100 t/day. Table 4 specifies the capital expenditure with general technical data, e.g. component, quantity and capacity. The total of the capital expenditure is then introduced to the calculation of the average unit costs of hydrogen (Table 5).

**Table 4: Calculation of capital expenditure for large natural gas reformer**

| Component | *Quantity* | *Unit* | *Price/Unit* | *Total* |
|---|---|---|---|---|
| Reformer plant (reference 30 t/day) | 1 | plant | 25.000.000,00 € | |
| Capacity (t/day) | 100 | | | |
| Reformer plant (100 t/day) | | | 51.483.404 € | 51.483.404 € |
| $H_2$ compressor 23-80 barg (2 x 100% capacity for 100 t/day) | 2 | unit | 5.000.000,00 € | 5.000.000 € |
| Piping, distribution, installation, miscellaneous H2 | n/a | | incl. | |
| | | | | |
| Land | 2.500,00 | m² | incl. | |
| Fence incl. gate | n/a | m | incl. | |
| | | | | |
| Off-sites (tie-in, NG dispenser, control room…) | n/a | % | incl. | |
| | | | | |
| **Subtotal** | | | | 56.483.404 € |
| | | | | |
| Project planning costs | 5 | % | 56.483.404,21 € | 2.824.170 € |
| | | | | |
| **Capital expenditure I** | | | | 59.307.574 € |

## Table 5: Costs for the provision of energy: Large natural gas reformer

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| NG costs | ng_s | | 0,022 | €/kWh HHV |
| Electricty costs | e_s | | 0,083 | €/kWh |
| Feed Water : steam generation system | w_s | | 2,6 | €/m³ |
| Export steam price | es_s | | 13 | €/t |
| Cooling water | cw_s | | 0,017 | €/m³ |
| Nitrogen | n_s | | 0,09 | €/Nm³ |
| Instrument Air | ar_s | | 0,015 | €/Nm³ |
| Labor hour cost | l_s | | 50 | €/h |
| Interest rate | i | | 9,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T - 1)$ | 0,124 | - |
| **Specific Consumption** | | | | |
| NG | ng | | 51207,8 | kWh/t $H_2$ HHV |
| Export steam | es | | 6,5 | t/t $H_2$ |
| Feed Water : steam generation system | w | | 16,9 | m³/t $H_2$ |
| Electricity : Instrument and Lightning | Ein | | 15,0 | kWh/t $H_2$ |
| Electricity : Aero cooler + Fans (flue gas and Air) | Eaer | | 150,0 | kWh/t $H_2$ |
| Electricity : Water pump | Epum | | 53,3 | kWh/t $H_2$ |
| Electricity : $H_2$ compression | Ecom | | 630,7 | kWh/t $H_2$ |
| Cooling water | cw | | 80,4 | $m^3$/t $H_2$ |
| Nitrogen | n | | 4,8 | $Nm^3$/t $H_2$ |
| Instrument Air | ar | | 36,0 | $Nm^3$/t $H_2$ |
| **Basic data** | | | | |
| Full load hours | f_l | | 8.000 | h/a |
| Power input | Pin | 100 / 24 * 1000 * 39,41 | 164.208 | kW HHV |
| NG | NG | ng * $E_{H2[t]}$ | 1.707 | GWh/a HHV |
| Export steam | ES | es * $E_{H2[t]}$ | 216.290 | t/a |
| Feed Water : steam generation system | W | w * $E_{H2[t]}$ | 563.283 | m³/a |
| Electricity : ISBL comsumption | Eisbl | (Ein+Ear+Epum) * $E_{H2[t]}$ /1000 | 7.277 | MWhe/a |
| Electricity : $H_2$ compression | E_com | Ecom * $E_{H2[t]}$ / 1000 | 21.022 | MWhe/a |
| Electricity consumption | E_c | Eisbl + E_c | 28.299 | MWhe/a |
| Cooling water | CW | cw * $E_{H2[t]}$ | 2.681.367 | m³/a |
| Nitrogen | N | n * $E_{H2[t]}$ | 160.000 | Nm³/a |
| Instrument Air | AR | ar * $E_{H2[t]}$ | 1.200.000 | Nm³/a |
| Annual $H_2$ Production | $E_{H2[t]}$ | 100/24 * f_l | 33.333 | t $H_2$/a |
| Annual $H_2$ Production | $E_{H2[Nm^3]}$ | 100/0.08988/24*1000*f_l | 370.864.857 | Nm³/a |
| Annual $H_2$ Production | $E_{H2[kWh]}$ | $E_{H2[Nm^3]}$ * 3.55 | 1.316.570.242 | kWh/a HHV |
| Capital expenditure | I | | 59.307.574 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 7.357.631 | €/a |
| NG costs | ANG | NG * 10^6 * ng_s | 37.552.381 | €/a |
| Export steam Income | ES_in | ES * es_s | 2.811.776 | €/a |
| Water costs | AWs | W * w_s + CW * cw_s | 1.510.119 | €/a |
| Electricity | AE | E_c * 1000 * e_s | 2.345.987 | €/a |
| Other consumptions | AC | N * n_s + AR * ar_s | 32.400 | €/a |
| Costs for service and maintenance | AS | I * 0.03 | 1.779.227 | €/a |
| Labor cost | AL. | l_s * 24 / 100 * $E_{H2[t]}$ | 400.000 | €/a |
| Miscellaneous costs (insur., taxes...) | AM | I * 0.02 | 1.186.151 | €/a |
| Total operating costs | K | ANG+AWs+AE+AC+AS+AL.+AM-ES_in | 41.994.490 | €/a |
| Total annual costs | AK | AN+K | 49.352.122 | €/a |
| **Specific costs for Large Reformer** | | | | |
| Costs of $H_2$ production | | AK / $E_{H2[Nm^3]}$ | 0,133 | €/Nm³ |
| Costs of $H_2$ production | | AK / $E_{H2[kWh]}$ | 0,037 | €/kWh |
| Costs of $H_2$ production | | AK / $E_{H2[t]}$ | 1480,564 | €/t $H_2$ |

The calculation of the average unit costs of hydrogen starts off with defining the economic boundary conditions (top section of Table 5), e.g. Natural Gas (NG) costs, electricity costs and depreciation period. The next section of the table compiles the specific consumption of inputs like natural gas and electricity. In the basic data section the total of the inputs and outputs can be found, as well as the annual hydrogen production. These data are needed to calculate the annual costs and to express these as specific costs. These can be found in Euro per normal cubic meter, per kilowatt hour and per ton for comfortable reading. The hydrogen costs for Natural Gas Reforming are 0,037 € per kWh (HHV) in the case shown here.

If this result is compared to [Prieur 2008] (section Hydrogen from natural gas) it can be seen that the result is in the same order of magnitude. The difference of 0,48 €/kg between the medium scale SMR (1,87 $/kg$_{2002}$ ~ 1,01 €/kg$_{2000}$, DoE 2002) and the large scale SMR in this document (1,48 €/kg$_{2008}$) is influenced by several parameters: firstly the inflation over 6 to 8 years has to be considered (since the former uses the year 2000/2002 as a reference), secondly, the natural gas price in Europe in 2008 was three times higher than the 19-year national average industrial rate in the US [DOE 2002]. Finally, the electricity price in Europe for 2008 was twice as high as the 10-year national average industrial rate in the US, which is used in [DOE 2002]. In [DOE 2002] Table 23 shows the costs per kg of hydrogen for an SMR of 6,75 and 25,4 Million Nm³/d ([Foster-Wheeler 1996 and Blok et al 1997]) which are much lower then the ones compiled in this document, but Table 5 is calculated for a production of only ~ 1 Million Nm³/d. This could explain the price difference, but as [DOE 2002] shows, there is a distinct influence of the detailed economic assumptions which results in a variety of hydrogen prices and the prices discussed in both reports should be regarded as ‘order of magnitude’ rather than reliable values for hydrogen costs.

### 3.1.2 Natural Gas Reforming (with CCS)

This section specifies the costs of a Natural Gas Reformer plant with Carbon Capture and Storage (CCS) of a capacity of 100 t/day. Table 6 describes the capital expenditure with the general technical data in analogy to Table 4. The costs for CCS are introduced as unitary costs per ton of hydrogen in the economic boundary condition section of Table 7.

**Table 6: Calculation of capital expenditure for large natural gas reformer**

| Component | *Quantity* | *Unit* | *Price/Unit* | *Total* |
|---|---|---|---|---|
| Reformer plant (reference 30 t/day) | 1 | plant | 25.000.000,00 € | |
| Capacity (t/day) | 100 | | | |
| Reformer plant (100 t/day) | | | 51.483.404 € | 51.483.404 € |
| $H_2$ compressor 23-80 barg (2 x 100% capacity for 100 t/day) | 2 | unit | 5.000.000,00 € | 5.000.000 € |
| Piping, distribution, installation, miscellaneous H2 | n/a | | incl. | |
| | | | | |
| Land | 2.500,00 | m² | incl. | |
| Fence incl. gate | n/a | m | incl. | |
| | | | | |
| Off-sites (tie-in, NG dispenser, control room…) | n/a | % | incl. | |
| | | | | |
| **Subtotal** | | | | 56.483.404 € |
| | | | | |
| Project planning costs | 5 | % | 56.483.404,21 € | 2.824.170 € |
| | | | | |
| **Capital expenditure I** | | | | 59.307.574 € |

## Table 7: Costs for the provision of energy: Large natural gas reformer with CCS

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| NG costs | ng_s | | 0,022 | €/kWh HHV |
| Electricty costs | e_s | | 0,083 | €/kWh |
| Feed Water : steam generation system | w_s | | 2,6 | €/m³ |
| Export steam price | es_s | | 13 | €/t |
| Cooling water | cw_s | | 0,017 | €/m³ |
| Nitrogen | n_s | | 0,09 | €/Nm³ |
| Instrument Air | ar_s | | 0,015 | €/Nm³ |
| Labor hour cost | l_s | | 50 | €/h |
| $CO_2$ Capture and geological storage | ccs_s | Unitary cost 60 €/T $CO_2$ | 514,62 | €/T H2 |
| Interest rate | i | | 9,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T-1)$ | 0,124 | - |
| **Specific Consumption** | | | | |
| NG | ng | | 51207,8 | kWh/t $H_2$ HHV |
| Export steam | es | | 6,5 | t/t $H_2$ |
| Feed Water : steam generation system | w | | 16,9 | m³/t $H_2$ |
| Electricity : Instrument and Lightning | Ein | | 15,0 | kWh/t $H_2$ |
| Electricity : Aero cooler + Fans (flue gas and Air) | Eaer | | 150,0 | kWh/t $H_2$ |
| Electricity : Water pump | Epum | | 53,3 | kWh/t $H_2$ |
| Electricity : $H_2$ compression | Ecom | | 630,7 | kWh/t $H_2$ |
| Cooling water | cw | | 80,4 | $m^3$/t $H_2$ |
| Nitrogen | n | | 4,8 | $Nm^3$/t $H_2$ |
| Instrument Air | ar | | 36,0 | $Nm^3$/t $H_2$ |
| **Basic data** | | | | |
| Full load hours | f_l | | 8.000 | h/a |
| Power input | Pin | 100 / 24 * 1000 * 39,41 | 164.208 | kW HHV |
| NG | NG | ng * $E_{H2[t]}$ | 1.707 | GWh/a HHV |
| Export steam | ES | es * $E_{H2[t]}$ | 216.290 | t/a |
| Feed Water : steam generation system | W | w * $E_{H2[t]}$ | 563.283 | m³/a |
| Electricity : ISBL comsumption | Eisbl | (Ein+Ear+Epum) * $E_{H2[t]}$ /1000 | 7.277 | MWhe/a |
| Electricity : $H_2$ compression | E_com | Ecom * $E_{H2[t]}$ / 1000 | 21.022 | MWhe/a |
| Electricity consumption | E_c | Eisbl + E_c | 28.299 | MWhe/a |
| Cooling water | CW | cw * $E_{H2[t]}$ | 2.681.367 | m³/a |
| Nitrogen | N | n * $E_{H2[t]}$ | 160.000 | Nm³/a |
| Instrument Air | AR | ar * $E_{H2[t]}$ | 1.200.000 | Nm³/a |
| Annual $H_2$ Production | $E_{H2[t]}$ | 100/24 * f_l | 33.333 | t $H_2$/a |
| Annual $H_2$ Production | $E_{H2[Nm^3]}$ | 100/0.08988/24*1000*f_l | 370.864.857 | Nm³/a |
| Annual $H_2$ Production | $E_{H2[kWh]}$ | $E_{H2[Nm^3]}$ * 3.55 | 1.316.570.242 | kWh/a HHV |
| Capital expenditure | I | | 59.307.574 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 7.357.631 | €/a |
| NG costs | ANG | NG * 10^6 * ng_s | 37.552.381 | €/a |
| Export steam Income | ES_in | ES * es_s | 2.811.776 | €/a |
| Water costs | AWs | W * w_s*1000 + CW * cw_s*1000 | 1.510.119 | €/a |
| Electricity | AE | E_c * 1000 * e_s | 2.345.987 | €/a |
| Other consumptions | AC | N * n_s + AR * ar_s | 32.400 | €/a |
| Costs for service and maintenance | AS | I * 0.03 | 1.779.227 | €/a |
| Labor cost | AL. | l_s * 24 / 100 * $E_{H2[t]}$ | 400.000 | €/a |
| Miscellaneous costs (insur., taxes...) | AM | I * 0.02 | 1.186.151 | €/a |
| $CO_2$ Capture and geological storage annual cost | CCS | ccs_s * $E_{H2[t]}$ | 17.154.000 | €/a |
| Total operating costs with $CO_2$ capture and storage | K | ANG+AWs+AE+AC+AS+AL.+AM+CCS-ES_in | 59.148.490 | €/a |
| Total annual costs with $CO_2$ capture and storage | AK | AN+K | 66.506.122 | €/a |
| **Specific costs for Large Reformer** | | | | |
| Costs of $H_2$ production with $CO_2$ capture an storage | | AK / $E_{H2[Nm^3]}$ | 0,179 | €/Nm³ |
| Costs of $H_2$ production with $CO_2$ capture an storage | | AK / $E_{H2[kWh]}$ | 0,051 | €/kWh |
| Costs of $H_2$ production with $CO_2$ capture an storage | | AK / $E_{H2[t]}$ | 1995,184 | €/t $H_2$ |

The main difference to section 3.1.1 is the inclusion of cost for Carbon Capture and Storage which can be found in the section ‘annual costs’. The costs of hydrogen production with $CO_2$ capture and storage are 0,051 €/kWh (HHV) in the case shown here. The costs for CCS per kg are 0,52 €/kg $H_2$ which is cheaper than the assumptions in [Prieur 2008] (Table 23) where costs for CCS of 0,72 and 1,03 €/kg $H_2$ are stated. Adjustments to the desired calculation scheme can be made in dependency of the basic assumptions and economical data that are to be followed.

### 3.1.3 Nuclear SI-Cycle

The sulphur – iodine cycle referred to here is a high temperature process in which hydrogen is separated out of water (steam) through a multi-step chemical reaction cycle between hydrogen, iodine and sulphuric acid (cf. [Nygaard 2008] for more detail). The cycle requires high temperatures as can be supplied by high temperature nuclear reactors (for instance Advanced Gas Cooled Reactors (AGR)) or concentrating solar thermal plants.

The costs stated here are derived from relevant documentation [Schultz 2002]. Data were found in US$$_{2006}$ only and converted to Euro at a currency rate of 1€ = 1.4388 US$ (cf. Table 9).

**Table 8: Calculation of Capital expenditure for a high temperature nuclear reactor with SI-Cycle [Schultz 2002]**

| Component | *Quantity* | *Unit* | *Price/Unit* | *Total* |
|---|---|---|---|---|
| Land and land rights | N/A | plant | $0 | $0 |
| Structures and improvements | n/a | unit | $132.000.000 | $132.000.000 |
| Reactor plant equipment | n/a | unit | $420.000.000 | $420.000.000 |
| Turbine plant equipment | n/a | unit | $0 | $0 |
| Electric plant equipment | n/a | unit | $50.000.000 | $50.000.000 |
| Miscellaneous plant equipment | n/a | unit | $28.000.000 | $28.000.000 |
| S-I System | n/a | unit | $417.000.000 | $417.000.000 |
| Intermediate loops crc. and piping | | | $73.000.000 | $73.000.000 |
| Indirect costs | | | | |
| Construction services | n/a | unit | $118.000.000 | $118.000.000 |
| Home office engineering and services | n/a | unit | $35.000.000 | $35.000.000 |
| Field office engineering and services | n/a | unit | $41.000.000 | $41.000.000 |
| Owner costs / I2 inventory | n/a | unit | $315.000.000 | $315.000.000 |
| | | | | |
| **Capital expenditure** | l | | $1.629.000.000 | $1.629.000.000 |

Table 9 states the cost of hydrogen as 2,45 €/kg (without $O_2$ credit) and 2,30 €/kg (with $O_2$ credit). These costs are in line with the production costs of 2,50 €/kg shown in [Prieur 2008] Table 54.

## Table 9: Cost for the provision of hydrogen from nuclear SI-Cycle

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Nuclear heat cost, incl. Capital recovery and operating | nh_s | | 13,14 | €/$MWh_{th}$ |
| Operating cost, incl. Nucl. Fuel cycle, waste disposal,O&M | O_c | incl. in nh_s | 5,77 | €/$MWh_{th}$ |
| Sulfuric acid cost | s_a_c | | 62,00 | €/t |
| electricity costs | e_s | | 70,00 | €/MWh |
| water cost | w_s | | 1,45 | €/m3 |
| $I_2$ cost | I2I | | 20 | €/kg |
| labour cost | l_s | | 50 | €/h |
| availability | ava | | 85 | % |
| full load hours | f_l | | 7.500 | h/a |
| Interest rate | i | | 10 | % |
| Depreciation period | t_s | | 30 | a |
| Annuity factor | a | $i * (1 + i)^t / ((1 + i)^t-1)$ | 0,11 | |
| **Specific consumption** | | | | |
| plant electricity requirement | p_e_r | | 2,6 | % |
| S-I $H_2$ electricity requirement | CCS_e_r | | 0,80 | % |
| heat consumption | c | | 94,40 | €/$MWh_{th}$/t |
| $I_2$ consumppion | I2_c | . | 2,40 | kg/h |
| water consumption | w | | 228,81 | $m^3$/h |
| $H_2SO_4$ | s_a_c | | 0,13 | kg/h |
| **Basic data** | | | | |
| Plant net output | P_out | | 2.400 | $MW_{th}$ |
| net $H_2$ plant output | P_out_H2 | P_out/c | 25 | t/hr |
| heat consumption | C | c *P_out_H2* f_l | 18.000.000,00 | €/$MWh_{th}$/a |
| electricity consumption | E_c | p_e_r * P_out * f_l / 100 | 468.000,00 | MWh/a |
| Water consumption | W | w * f_l | 1.716.105 | m³/a |
| $I_2$ consumption | I2_C | I2_c * f_l | 18.000 | kg/a |
| $H_2$ annual output | H2_A | P_out_H2*f_l | 190.678 | t/a |
| $O_2$ production | $O_2$_pr | P_out_H2*8 | 203,39 | $t_{O2}$ /h |
| $O_2$ credit annual | $O_2$_cr_a | (O2_pr*f_l)*20€ | 30.508.474,58 | €/a |
| $H_2SO_4$ consumption | S_A_c | s_a_c*f_l | 0,94 | $t_{H2SO4}$ /a |
| Thermal efficiency of $H_2$ production | eff | | 0,42 | |
| Electricity production efficiency | eff_e_p | | 0,50 | |
| captial expenditure | I | | 1.132.193.000 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 120.102.182 | €/a |
| heat cost | ACs | C * nh_s | 236.520.000 | €/a |
| sulfuric acid cost | SA | s_a_c* | 58,13 | €/a |
| electricity costs | AE | E_c * e_s | 32.760.000 | €/a |
| water costs | AW | W * w_s | 2.488.352,25 | €/a |
| $I_2$ costs | I2M | AM_c * am_s | 360.000,00 | €/a |
| labour costs | L | l_s * f_l * 260 * (ava/100) | 82.875.000 | €/a |
| total annual costs **without** $0_2$ credit | ACo | AN+ACs+SA+AE+AW +I2M+L | 475.105.592,69 | €/a |
| total annual costs with $0_2$ credit | ACwO | Aco-O2_cr_a | 444.597.118,12 | €/a |
| **Specific costs for 4X600 MWth Nuclear Plant** | | | | |
| Costs of hydrogen production (w/o $O_2$ credit) | | ACo / H2_A | 2.491,66 | €/t |
| Costs of hydrogen production (w/o $O_2$ credit) | | ACo / H2_A / 1000 * 0.0899 | 0,224 | €/Nm³ |
| Costs of hydrogen production (w/o $O_2$ credit) | | ACo / H2_A / 1000 / 39.41 | 0,063 | €/$kWh_{H2}$ |
| Costs of hydrogen production **(with $O_2$ credit)** | | ACwO/H2_A | 2.331,66 | €/t |
| Costs of hydrogen production **(with $O_2$ credit)** | | ACwO/H2_A / 1000 * 0.0899 | 0,210 | €/Nm³ |
| Costs of hydrogen production **(with $O_2$ credit)** | | ACwO/H2_A / 1000 / 39.41 | 0,059 | €/$kWh_{H2}$ |

### 3.1.4 Electrolysis

The third process producing hydrogen directly is electrolysis. The following tables (Table 10 to Table 14) use the average grid electricity cost in Europe (2008) for industrial applications as an input. In calculating the cost from a production chain analysis the cost of electricity from the sources described in Section 3.2 have to be inserted instead.

The costs of hydrogen production with large electrolysis is stated in Table 12 as 0,156 €/kWh (6,15 €/kg$_{HHV}$) and is therefore approximately 50% higher than in [Prieur 2008], Table 56. The reasons for this are the differing electricity costs and other variations in input values. It is also important to note the influence of inflation, since [Prieur 2008] used values from 2000 when assessing the state of the art.

Large electrolysis is the most interesting technology to produce hydrogen with electricity from renewable energy or nuclear power. Therefore the electricity price is an important input factor for the costs of hydrogen from electrolysis. Another important input factor is the depreciation period. With electrolysis it is sometimes not clear how reliable the technology is. Table 13 and Table 14 show the effect of a change in these input factors. Table 13, for example, shows the decreasing influence of an extended depreciation period where as Table 14 shows a more or less linear influence of an increasing electricity price.

**Table 10: Allocation of land and fencing for a large electrolysis plant**

| | Area (baseplate) | Proportion land | Proportion fence |
|---|---|---|---|
| **A Electrolysis** | | | |
| Electrolyser | n/a | n/a | n/a |
| Incl. Buffer storage | n/a | n/a | n/a |
| Ex-regulated area | >27.000 m² | | |
| **Subtotal** | **0,00 m²** | | |
| **Area to be allocated** | | | |
| Baseplate (sealed area, concrete)) | 0,00 m² | *0,00 m²* | *0,00 m* |
| Land in total | 17.600,00 m² | | |
| Fence incl. gate | 380,00 m | | |

**Table 11: Calculation of capital expenditure for an electrolysis plant**

| Component | *Quantity* | *Unit* | *Price/Unit* | *Total* |
|---|---|---|---|---|
| Electrolyser plant **(250 MW)** | 1 | plant | 166.996.047,83 € | 166.996.048 € |
| Electrolysers, 485 Nm³/h | ~ 104 | unit | incl. | |
| Buffer | n/a | unit | incl. | |
| Low pressure compressor 8 bar | n/a | unit | incl. | |
| Cooling (incl. cooling for compression to 150 bar) | n/a | unit | incl. | |
| Feed water demineralizer | n/a | unit | incl. | |
| Deoxidiser | n/a | unit | incl. | |
| Gas dryer | n/a | unit | incl. | |
| Piping, distribution, installation, miscellaneous | n/a | unit | incl. | |
| | | | | |
| Land | n/a | m² | incl. | |
| therefrom area with potentially explosive atmosphere | > 27.000 | m² | incl. | |
| Baseplate | n/a | m² | incl. | |
| Fence incl. gate | n/a | m | incl. | |
| | | | | |
| Transformer station (310 MW) proportional | 97 | % | 5.000.000,00 € | 4.850.000 € |
| Water supply (hooking to water mains) | 1 | unit | incl. | |
| Sewage hook-up | 1 | unit | incl. | |
| | | | | |
| **Subtotal** | | | | 171.846.048 € |
| | | | | |
| Project planning costs | 5 | % | 171.846.047,83 € | 8.592.302 € |
| | | | | |
| **Capital expenditure $I^A$** | | | | 180.438.350 € |

**Table 12: Costs for the provision of hydrogen: large electrolysis plant**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Electricity costs | s | | 0,091 | €/kWh |
| Water costs | wk | | 1,45 | €/m³ |
| Interest rate | i | | 9,00 | % |
| Depreciation period | T | | 10 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T - 1)$ | 0,156 | - |
| **Specific consumption** | | | | |
| Water consumption | w | | 1,00 | $L/Nm^3_{H2}$ |
| **Basic data** | | | | |
| Full load hours | v | | 6.500,00 | h/a |
| Power input | P | | 250.000,00 | kW |
| Electricity consumption | m | v * P | 1.625.000.000,00 | kWh/a |
| Water quantity | wm | $w * 'E_{H2[Nm^3]} / 1000$ | 328.947,37 | m³/a |
| System efficiency factor A | η | | 0,72 | - |
| Secondary energy quantity $H_2$ | $E_{H2[Nm^3]}$ | m * η / 3,54 | 328.947.368,42 | Nm³/a |
| Secondary energy content $H_2$ | $E_{H2[kWh]}$ | m * η | 1.164.473.684,21 | kWh/a |
| Captial expenditure | $I^A$ | | 180.438.350,22 | € |
| **Annual costs** | | | | |
| Capacity costs | AN | I * a | 28.115.919,95 | €/a |
| Power costs | S | s * m | 147.875.000,00 | €/a |
| Water costs | WK | wk * wm | 476.973,68 | €/a |
| Costs for service and maintenance | W | $E_{H2[Nm^3]}$ * 0,008463 € | 2.783.881,58 | €/a |
| Miscellaneous costs (insur., equipment...) | SK | $E_{H2[Nm^3]}$ * 0,008463 € | 2.783.881,58 | €/a |
| Total operating costs | BK | S + WK + W + SK | 153.919.736,84 | €/a |
| Total annual costs | K | AN + BK | 182.035.656,80 | €/a |
| **Specific costs for A** | | | | |
| Secondary energy unit costs $H_2$ | $k_{H2[Nm^3]}$ | K / $E_{H2[Nm^3]}$ | 0,553 | €/Nm³ |
| Secondary energy unit costs $H_2$ | $k_{H2[kWh]}$ | K / $E_{H2[kWh]}$ | 0,156 | €/kWh |

**Table 13: Sensitivity of the hydrogen price with respect to the depreciation period**

| | | | | | |
|---|---|---|---|---|---|
| Depreciation period | 5 | 10 | 15 | 20 | years |
| Secondary energy unit costs $H_2$ | 0,609 | 0,553 | 0,536 | 0,528 | €/Nm³ |
| Secondary energy unit costs $H_2$ | 0,172 | 0,156 | 0,151 | 0,149 | €/kWh |

**Table 14: Sensitivity of the hydrogen price with respect to the electricity price**

| | | | | | |
|---|---|---|---|---|---|
| Electricity price | 0,05 | 0,07 | 0,091 | 0,11 | €/kWh |
| Secondary energy unit costs $H_2$ | 0,351 | 0,450 | 0,553 | 0,647 | €/Nm³ |
| Secondary energy unit costs $H_2$ | 0,099 | 0,127 | 0,156 | 0,183 | €/kWh |

## 3.2 Electricity Producing Processes

This section gives an overview of the costs of the main low carbon emission technologies in electricity production. Electricity producing processes need a subsequent electrolysis step in which water is split into hydrogen and oxygen. This means we have a two-step process, as shown in Table 1 and described in Chapter 2.1, for producing hydrogen.

It has to be noted, that the 'Electricity Producing Process' models presented here are representative of the calculation scheme. They use 'typical' values in the tables, but in do not mean to deliver specific predictions of actual or future electricity prices.

### 3.2.1 Wind Power Onshore

The calculation of the cost of electricity from Wind Power Onshore starts off with Table 15 with the allocation of land and fence for the base area of one 1 MW turbine. The base is 30 m² and the land needed in total is 66.666 m². This is the average consumption of area onshore for wind turbines, considering the usual rules of distances in siting turbines.

**Table 15: Allocation of land and fencing for a wind farm onshore**

| | Area (baseplate) |
|---|---|
| **A Wind Farm** | |
| Foundations | 30,00 m² |
| Exclusion zones | 66.666,00 |
| **Area to be allocated** | |
| Base area | 30,00 m² |
| Land in total | 66.666,00 m² |

In Table 16 the calculation of capital expenditure for a wind farm is shown. To understand the cost structure of the wind farm it is split roughly into percentage numbers, e.g. 68% of the investment for the wind turbine and 4% for the foundations. The contribution of the tower is not indicated, although this is mainly made of steel and the steel prices have risen significantly during the last years. Unfortunately the data for the amount of steel were not available.

The price per kW installed has a range between 800 and 1.400 €/kW. The capital expenditure is brought forward into Table 17.

**Table 16: Calculation of capital expenditure for wind farm onshore**

| Component | Quantity | Unit | Price/Unit | Total |
|---|---|---|---|---|
| Wind Farm (1 MW) | 1.000.000 | W | 1,20 € | 1.200.000 € |
| Wind Turbine (per MW) | | unit | 68,0% | |
| Tower | | unit | | |
| Access roads | | unit | 2,7% | |
| Foundations | | unit | 4,0% | |
| Transformer station | | unit | 4,1% | |
| Electrical connection | | unit | 9,3% | |
| Other expenses | | unit | 6,0% | |
| | n/a | unit | | |
| | | | | |
| Land | 66.666,67 | m² | | |
| thereof land actually used | < 200 | m² | | |
| Foundation | 30,00 | m² | X € | X € |
| Fence incl. gate | n/a | m | | |
| | | | | |
| | | | | 0 € |
| | | | | |
| | | | | |
| | | | | |
| **Subtotal** | | | | 1.200.000 € |
| | | | | |
| Project planning costs | 5 | % | 1.200.000,00 € | 60.000 € |
| | | | | |
| **Capital expenditure I** | | | | 1.260.000 € |

The cost of wind energy production is calculated in Table 17 starting with the economic boundary conditions like the electricity costs for the auxiliary power needs during times with no wind, the interest rate, the depreciation period and the annuity factor. In the basic data section the typical capacity factor for an onshore wind farm, the power output, the annual energy production and the capital expenditure are shown. The following section gives the annual costs, including the annuity, power costs, costs for O&M, miscellaneous costs, resulting in the total operating and annual costs. The cost of onshore wind energy production in this example is 0,074 €/kWh, which corresponds well to German wind energy production figures.

**Table 17: Costs for the provision of energy: wind farm onshore**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Electricity costs | s | | 0,091 | €/kWh |
| Interest rate | i | | 7,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T - 1)$ | 0,110 | - |
| **Basic data** | | | | |
| Full load hours | v | | 2.500,00 | h/a |
| Power output | P | | 1.000,00 | kW |
| Annual Energy Production | *AEP* | P * v | 2.500.000,00 | kWh |
| Capital expenditure | I | | 1.260.000,00 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 138.341,23 | €/a |
| Power costs | S | s * 0,5% * P * 8760 h | 3.985,80 | €/a |
| Costs for service and maintenance | W | I * 2% | 25.200,00 | €/a |
| Miscellaneous costs (insur., equipment...) | SK | I * 1% | 12.600,00 | €/a |
| Total operating costs | K | S + W + SK | 41.785,80 | €/a |
| Total annual costs | AK | AN + K | 180.127,03 | €/a |
| **Specific costs for wind onshore** | | | | |
| Cost of Wind energy production | $k_{[kWh]}$ | AK / AEP | 0,072 | €/kWh |

### 3.2.2 Wind Power Offshore

The calculation for Wind Power Offshore starts off in Table 18 with the allocation of land use and fencing. The base area for one 1 MW turbine is left out in the offshore case and the 'land' use (sea surface use, to be more precise) in total is 100.000 m². This calculation considers the average spacing offshore for avoiding mutual influences of turbines on each others power production.

**Table 18: Allocation of 'land and fence' for wind farm offshore**

| | Area (baseplate) |
|---|---|
| **A Wind Farm** | |
| Foundations | 0,00 m² |
| Exclusion zones | 100.000,00 |
| **Area to be allocated** | |
| Base area | 0,00 m² |
| Land in total | 100.000,00 m² |
| | |

In Table 19 the calculation of capital expenditure for an offshore wind farm is shown. The costs for the offshore wind farm are higher than for an onshore site since the higher mechanical stresses at sea increase construction costs. Only the access road can be left away since this is not applicable. The price per kW installed of wind farms offshore cannot be based on experience yet due to a lack of realised projects. A range between 1.400 and 2.000 €/kW is assumed.

**Table 19: Calculation of capital expenditure for wind farm offshore**

| **Component** | ***Quantity*** | ***Unit*** | ***Price/Unit*** | ***Total*** |
|---|---|---|---|---|
| Wind Farm (1 MW) | 1.000.000 | W | 1,80 € | 1.800.000 € |
| Wind Turbine (per MW) | | unit | | |
| Tower | | unit | | |
| Access roads | | unit | 0 € | |
| Foundation | | unit | | |
| Erection | | unit | | |
| | n/a | unit | | |
| | | | | |
| Land | 100.000,00 | m² | | |
| thereof land actually used | 0,00 | m² | | |
| Foundation | 30,00 | m² | X € | X € |
| Fence incl. gate | n/a | m | | |
| | | | | |
| **Subtotal** | | | | 1.800.000 € |
| | | | | |
| Project planning costs | 5 | % | 1.800.000,00 € | 90.000 € |
| | | | | |
| **Capital expenditure I** | | | | 1.890.000 € |

The Cost of offshore wind energy production in Table 20 is calculated in analogy to Table 17. The capacity factor offshore is considerably higher than onshore. Final cost of offshore wind energy production for the given example results as 0,098 €/kWh, which again is in line with German offshore expectations.

**Table 20: Costs for the provision of energy: wind farm offshore**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Electricity costs | s | | 0,091 | €/kWh |
| Interest rate | i | | 8,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T - 1)$ | 0,117 | - |
| **Basic data** | | | | |
| Full load hours | v | | 3.000,00 | h/a |
| Power output | P | | 1.000,00 | kW |
| Annual Energy Production | *AEP* | P * v | 3.000.000,00 | kWh |
| Capital expenditure | I | | 1.890.000,00 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 220.807,84 | €/a |
| Power costs | S | s * 1% * P * 8760 h | 7.971,60 | €/a |
| Costs for service and maintenance | W | I * 2,5% | 37.800,00 | €/a |
| Miscellaneous costs (insur., equipment...) | SK | I * 1% | 18.900,00 | €/a |
| Total operating costs | K | S + W + SK | 64.671,60 | €/a |
| Total annual costs | AK | AN + K | 285.479,44 | €/a |
| **Specific costs for Wind offshore** | | | | |
| Costs of Wind energy production | $k_{[kWh]}$ | AK / AEP | 0,095 | €/kWh |

### 3.2.3 Hydro Power

After looking into typical hydro projects and taking the analysis of Roads2HyCom Deliverable 2.2 “Potential of Emerging and Future $CO_2$-Neutral Hydrogen Sources on the European Scale” (document reference R2H2008PU.1, [Nygaard 2008]) into account, it was concluded that there are no ‘prototypical’ hydro energy installations that would be representative of a major European contribution to electricity supply. Generally, no potential is seen for large projects in Europe anymore. Though quite a number of small installations, for instance as refurbishment and retrofitting of existing micro hydro sites, is seen as viable, their original contribution to hydrogen production in Europe (other than supplying electricity to the grid that might eventually be used in electrolysis somewhere) appears marginal.

Therefore no cost model is presented here.

### 3.2.4 Photovoltaics – Northern Europe

The calculations for photovoltaic power have to discern between the Northern and Southern European situation (determined by the total annual insolation on the PV array) and between roof mounted and 'farm' installations. All cases will differ with respect to the cost of land use and total energy production.

In the roof mounted cases no contribution from land use is accounted for, since obviously, the roof as part of a building will exist independently. The availability is taken as granted, since the array will otherwise not be installed. In the case of PV farms, land use has to be calculated in the same way as for onshore wind energy.

All calculations refer to a 1 MW installation.

Cost breakdown in the tables is stated in analogy to the previous calculations for wind energy. The resulting cost for Northern Europe is in correspondence with the German feed-in tariff, which again is based on (projected) actual costs. The capacity factor is limited to 1 000 h/yr.

#### *3.2.4.1 Northern Europe (roof mounted)*

**Table 21: Allocation of land and fence for PV roof mounted in North Europe**

| | Area (baseplate) | Proportion land | Proportion fence |
|---|---|---|---|
| **PV array** | | | |
| Foundations | 0,00 m² | n/a | n/a |
| Exclusion zones | 0,00 | n/a | n/a |
| | | | |
| **Subtotal** | **0,00 m²** | | |
| **Area to be allocated** | | | |
| Base area | 0,00 m² | *0,00 m²* | *0,00 m* |
| Land in total | 0,00 m² | | |
| | | | |

**Table 22: Calculation of capital expenditure for roof mounted PV in Northern Europe**

| Component | Quantity | Unit | Price/Unit | Total |
|---|---|---|---|---|
| PV array, roof mounted (1 MW) | 1.000.000 | W | | |
| PV modules (per module of 1 kW) | 1000 | modules | 1.500 € | 1.500.000 € |
| Roof mounting | 1000 | sets | 50 € | 50.000 € |
| | | | | |
| Cables | 10000 | m | 2 € | 20.000 € |
| DC/AC converter | 1000 | units | 880 € | 880.000 € |
| Electrical connection | 1 | gear | 10.000 € | 10.000 € |
| Other expenses (contingency) | | unit | 5,0% | 123.000 € |
| | n/a | unit | | |
| | | | | |
| Land use | 0,00 | m² | | |
| thereof land actually used | 0,00 | m² | | |
| Foundations | 0,00 | m² | | |
| Fence incl. gate | n/a | m | | |
| | | | | |
| | | | | |
| Labour (4 h per module) | 4000 | h | 50 € | 200.000 € |
| cranes and tools | 200 | h | 200 € | 40.000 € |
| | | | | |
| **Subtotal** | | | | 2.823.000 € |
| | | | | |
| Project planning costs | 5 | % | 2.823.000,00 € | 141.150 € |
| | | | | |
| **Capital expenditure I** | | | | 2.964.150 € |

**Table 23: Costs for the provision of energy: roof mounted PV in Northern Europe**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Interest rate | i | | 7,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^{T} / ((1 + i)^{T}-1)$ | 0,110 | - |
| **Basic data** | | | | |
| Full load hours | v | | 900,00 | h/a |
| Power output | P | | 1.000,00 | kW |
| Annual Energy Production | *AEP* | P * v | 900.000,00 | kWh |
| Capital expenditure | I | | 2.964.150,00 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 325.447,74 | €/a |
| Costs for service and maintenance | W | I * 0.5% | 14.820,75 | €/a |
| Miscellaneous costs (insur., equipment...) | SK | I * 1.5% | 44.462,25 | €/a |
| Total operating costs | BK | W + SK | 59.283,00 | €/a |
| Total annual costs | K | AN + BK | 384.730,74 | €/a |
| **Specific costs for PV roof mounted NE** | | | | |
| | | | | |
| Cost of PV energy production | $k_{[kWh]}$ | K / AEP | 0,427 | €/kWh |

### *3.2.4.2 Northern Europe (PV farm)*

**Table 24: Allocation of land and fence for PV farm in Northern Europe**

| | Area (baseplate) | Proportion land | Proportion fence |
|---|---|---|---|
| **PV Farm** | | | |
| Foundations | 1.000,00 m² | n/a | n/a |
| Exclusion zones | 21.000,00 m² | n/a | n/a |
| | | | |
| **Subtotal** | **22.000,00 m²** | | |
| **Area to be allocated** | | | |
| Foundations | 1.000,00 m² | *0,00 m²* | *0,00 m* |
| Area covered | 7.000,00 m² | | |
| Land in total | 21.000,00 m² | | |
| | | | |

**Table 25: Calculation of capital expenditure for PV farm in Northern Europe**

| Component | Quantity | Unit | Price/Unit | Total |
|---|---|---|---|---|
| PV array, rig mounted in field (1 MW) | 1.000.000 | W | | |
| PV modules (per module of 1 kW) | 1000 | modules | 2.000 € | 2.000.000 € |
| Foundations | 1000 | pairs | 250 € | 250.000 € |
| Mounting Rig | 1000 | sets | 250 € | 250.000 € |
| Cables | 10000 | m | 2 € | 20.000 € |
| DC/AC converter | 1000 | units | 880 € | 880.000 € |
| Grid switching connector | 1 | gear | 10.000 € | 10.000 € |
| Other expenses (contingency) | | unit | 5,0% | 70.500 € |
| | | | | |
| Land use | 21.000,00 | m² | | |
| thereof land actually used | 7.000,00 | m² | | |
| Foundations | 1.000,00 | m² | | |
| Fence incl. gate | 579,66 | m | | |
| | | | | |
| | | | | |
| Labour (4 h per module) | 4000 | h | 50 € | 200.000 € |
| cranes and tools | 200 | h | 200 € | 40.000 € |
| | | | | |
| **Subtotal** | | | | 3.720.500 € |
| | | | | |
| Project planning costs | 5 | % | 3.720.500,00 € | 186.025 € |
| | | | | |
| **Capital expenditure I** | | | | 3.906.525 € |

**Table 26: Costs for the provision of energy: PV farm in Northern Europe**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Interest rate | i | | 7,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T-1)$ | 0,110 | - |
| **Basic data** | | | | |
| Full load hours | v | | 1.000,00 | h/a |
| Power output | P | | 1.000,00 | kW |
| Annual Energy Production | *AEP* | P * v | 1.000.000,00 | kWh |
| Capital expenditure | I | | 3.906.525,00 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 428.915,45 | €/a |
| Costs for service and maintenance | W | I * 1.5% | 58.597,88 | €/a |
| Miscellaneous costs (insur., equipment...) | SK | I * 1.5% | 58.597,88 | €/a |
| Total operating costs | BK | W + SK | 117.195,75 | €/a |
| Total annual costs | K | AN + BK | 546.111,20 | €/a |
| **Specific costs for PV farm NE** | | | | |
| | | | | |
| Cost of PV energy production | $k_{[kWh]}$ | K / AEP | 0,546 | €/kWh |

### 3.2.5 Photovoltaic – Southern Europe

This case is characterised by a higher capacity factor of 1300 h/yr due to the increased insolation in Southern latitudes. All other parameters are chosen as stated for the Northern Europe cases. The higher capacity factor results in lower overall cost of electricity.

### 3.2.5.1 Southern Europe (roof mounted)

**Table 27: Allocation of land and fence for roof mounted PV in Southern Europe**

| | Area (baseplate) | Proportion land | Proportion fence |
|---|---|---|---|
| **A PV array** | | | |
| Foundations | 0,00 m² | n/a | n/a |
| Exclusion zones | 0,00 | n/a | n/a |
| | | | |
| **Subtotal** | **0,00 m²** | | |
| **Area to be allocated** | | | |
| Base area | 0,00 m² | *0,00 m²* | *0,00 m* |
| Land in total | 0,00 m² | | |
| | | | |

**Table 28: Calculation of capital expenditure for roof mounted PV in Southern Europe**

| **Component** | ***Quantity*** | ***Unit*** | ***Price/Unit*** | ***Total*** |
|---|---|---|---|---|
| PV array, roof mounted (1 MW) | 1.000.000 | W | | |
| PV modules (per module of 1 kW) | 1000 | modules | 1.500 € | 1.500.000 € |
| Roof mounting | 1000 | sets | 50 € | 50.000 € |
| Cables | 10000 | m | 2 € | 20.000 € |
| DC/AC converter | 1000 | units | 880 € | 880.000 € |
| Electrical connection | 1 | gear | 10.000 € | 10.000 € |
| Other expenses (contingency) | | unit | 5,0% | 123.000 € |
| | | | | |
| Land use | 0,00 | m² | | |
| thereof land actually used | 0,00 | m² | | |
| Foundations | 0,00 | m² | | |
| Fence incl. gate | n/a | m | | |
| | | | | |
| Labour (4 h per module) | 4000 | h | 50 € | 200.000 € |
| cranes and tools | 200 | h | 200 € | 40.000 € |
| | | | | |
| **Subtotal** | | | | 2.823.000 € |
| | | | | |
| Project planning costs | 5 | % | 2.823.000,00 € | 141.150 € |
| | | | | |
| **Capital expenditure I** | | | | 2.964.150 € |

**Table 29: Costs for the provision of energy: roof mounted PV in Southern Europe**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Interest rate | i | | 7,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T - 1)$ | 0,110 | - |
| **Basic data** | | | | |
| Full load hours | v | | 1.300,00 | h/a |
| Power output | P | | 1.000,00 | kW |
| Annual Energy Production | *AEP* | P * v | 1.300.000,00 | kWh |
| Capital expenditure | I | | 2.964.150,00 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 325.447,74 | €/a |
| Costs for service and maintenance | W | I * 0.5% | 14.820,75 | €/a |
| Miscellaneous costs (insur., equipment...) | SK | I * 1.5% | 44.462,25 | €/a |
| Total operating costs | BK | W + SK | 59.283,00 | €/a |
| Total annual costs | K | AN + BK | 384.730,74 | €/a |
| **Specific costs for PV roof mounted SE** | | | | |
| | | | | |
| Cost of PV energy production | $k_{[kWh]}$ | K / AEP | 0,296 | €/kWh |

### *3.2.5.2 Southern Europe (PV Farm)*

**Table 30: Allocation of land and fence for PV farm in Southern Europe**

| | Area (baseplate) | Proportion land | Proportion fence |
|---|---|---|---|
| **A PV Farm** | | | |
| Foundations | 1.000,00 m² | n/a | n/a |
| Exclusion zones | 21.000,00 m² | n/a | n/a |
| | | | |
| **Subtotal** | **22.000,00 m²** | | |
| **Area to be allocated** | | | |
| Foundations | 1.000,00 m² | *0,00 m²* | *0,00 m* |
| Area covered | 7.000,00 m² | | |
| Land in total | 21.000,00 m² | | |
| | | | |

**Table 31: Calculation of capital expenditure for PV farm in Southern Europe**

| Component | Quantity | Unit | Price/Unit | Total |
|---|---|---|---|---|
| PV array, rig mounted in field (1 MW) | 1.000.000 | W | | |
| PV modules (per module of 1 kW) | 1000 | modules | 2.000 € | 2.000.000 € |
| Foundations | 1000 | pairs | 250 € | 250.000 € |
| Mounting Rig | 1000 | sets | 250 € | 250.000 € |
| Cables | 10000 | m | 2 € | 20.000 € |
| DC/AC converter | 1000 | units | 880 € | 880.000 € |
| Grid switching connector | 1 | gear | 10.000 € | 10.000 € |
| Other expenses (contingency) | | unit | 5,0% | 70.500 € |
| | | | | |
| Land use | 21.000,00 | m² | | |
| thereof land actually used | 7.000,00 | m² | | |
| Foundations | 1.000,00 | m² | | |
| Fence incl. gate | 579,66 | m | | |
| | | | | |
| | | | | |
| Labour (4 h per module) | 4000 | h | 50 € | 200.000 € |
| cranes and tools | 200 | h | 200 € | 40.000 € |
| | | | | |
| **Subtotal** | | | | 3.720.500 € |
| | | | | |
| Project planning costs | 5 | % | 3.720.500,00 € | 186.025 € |
| | | | | |
| **Capital expenditure I** | | | | 3.906.525 € |

**Table 32: Costs for the provision of energy: PV farm in Southern Europe**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Interest rate | i | | 7,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T - 1)$ | 0,110 | - |
| **Basic data** | | | | |
| Full load hours | v | | 1.800,00 | h/a |
| Power output | P | | 1.000,00 | kW |
| Annual Energy Production | *AEP* | P * v | 1.800.000,00 | kWh |
| Capital expenditure | I | | 3.906.525,00 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 428.915,45 | €/a |
| Costs for service and maintenance | W | I * 1.5% | 58.597,88 | €/a |
| Miscellaneous costs (insur., equipment...) | SK | I * 1.5% | 58.597,88 | €/a |
| Total operating costs | BK | W + SK | 117.195,75 | €/a |
| Total annual costs | K | AN + BK | 546.111,20 | €/a |
| **Specific costs for PV Farm SE** | | | | |
| | | | | |
| Cost of PV energy production | $k_{[kWh]}$ | K / AEP | 0,303 | €/kWh |

### 3.2.6 Nuclear Electricity

The following tables follow a slightly different approach than the previous ones since detailed cost information concerning power station construction was not available. In view of the recent rises in concrete and steel prices that have led to the abandonment of various power station projects and severe cost increases with others [HB 2008], the identification of the influence of raw material cost would be of high interest in order to estimate future cost developments. The most recent Finnish nuclear reactor project has already experienced cost increases by 1500 to 2200 M€ up to the middle of 2008 [KSA 2008].

It should also be noted that in the annual cost no provision is made for the liability insurance of operation. These costs are regularly not (fully) carried by the operator but by state guarantee, since insurances are not available at commercial rates due to the character of the operating risk. It is difficult to valorise this state subsidy and therefore no attempt was made to do so, since it can be expected that nuclear electricity would otherwise not be economically viable, a judgement that cannot be made in the context of this study.

In contrast to Table 9, which analyse nuclear heat coupling to a high temperature hydrogen production process, the following tables refer to a Light Water Reactor (LWR), the standard type of reactor worldwide. The output of the process (calculation) is the electricity that is then fed to an electrolyser.

**Table 33: Calculation of capital expenditure for Nuclear Electricity**

**The middle columns state the breakdown of the total cost (bottom right field) in percentages.**

| **Component** | ***Factory Equipment Cost*** | ***Site Labour Cost*** | ***Site Material Cost*** | ***Account Costs as Percentage of Total Costs*** | ***Example Plant*** |
|---|---|---|---|---|---|
| Structures and improvements | 1,60 | 7,70 | 4,50 | 13,90 | 177.920.000 |
| Reactor plant equipment | 17,00 | 2,50 | 0,90 | 20,40 | 261.120.000 |
| Turbine plant equipment | 12,50 | 1,70 | 0,50 | 14,70 | 188.160.000 |
| Electric plant equipment | 2,50 | 1,30 | 0,60 | 4,40 | 56.320.000 |
| Miscellaneous plant equipment | 1,50 | 1,30 | 0,40 | 3,10 | 39.680.000 |
| Main cond. heat rej. system | 2,20 | 1,00 | 0,20 | 3,40 | 43.520.000 |
| **Total direct costs** | 37,30 | 15,40 | 7,00 | 59,90 | 766.720.000 |
| Construction services | 3,50 | 5,00 | 4,50 | 13,00 | 166.400.000 |
| Home office engineering and services | 6,40 | | | 6,40 | 81.920.000 |
| Field office engineering and services | 4,30 | 0,60 | 0,60 | 5,60 | 71.680.000 |
| Owner cost | | | | 5,10 | 65.280.000 |
| Contingency | | | | 10,00 | 128.000.000 |
| Foake | | | | Already paid | Already paid |
| **Total** | I | | | 100,00% | 1.280.000.000 |

**Table 34: Costs for the provision of energy: Nuclear Electricity**

**(Currency rate 1€ = US$1.20 (June 2004))**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| Reactor type (specifications) | LWR | | | |
| **Economic boundary conditions** | | | | |
| Nuclear variable O&M | VO_c | | 1,75 | €/MWh el. |
| Nucl. Fuel cycle, waste disposal | NF_c | | 4,50 | €/MWh el. |
| water cost | w_s | | 1,45 | €/m³ |
| Fixed O&M cost | FO_c | | 50.000 | €/MW.a |
| availability | ava | | 85 | % |
| full load hours | f_l | | 7.446,00 | h/a |
| Interest rate | i | | 9,00 | % |
| Depreciation period | t_s | | 10 | a |
| Annuity factor | a | $i * (1 + i)^t / ((1 + i)^t - 1)$ | 0,156 | |
| **Specific consumption** | | | | |
| water consumption | w | | 2.000,00 | $m^3/h$ |
| **Basic data** | | | | |
| Plant net output | P_out | | 1.000 | MWel |
| Water consumption | W | w * f_l | 14.892.000 | m³/a |
| Electricity production efficiency | eff_e_p | | 0.33 | |
| captial expenditure | I | | 1.280.000.000 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 199.449.715 | €/a |
| water costs | AW | W * w_s | 21.593.400 | €/a |
| Fuel and O&M | FOM | (VO_c+NF_c) * f_l +FO_c*P_out | 50.046.538 | €/a |
| total annual costs | ACo | AN+AW+FOM | 318.305.000 | €/a |
| **Specific costs for Nuclear Plant** | | | | |
| Cost of electricity | | ACo/ (P_out*f_l) | 42,75 | €/MWh el. |
| Cost of electricity | | ACo/ (P_out*f_l) /1000 | 0,04 | €/kWh el. |

### 3.2.7 Coal Gasification (with CCS)

The following tables are again based on total cost quotes found in [DTI 2006], [Ewan 2005], [IE 2006], [Rao 2004], [Rao 2007], [Panesar 2006]. For the sake of comparability with wind, solar and nuclear sources of electricity only the implementation with carbon capture and sequestration (CCS) is chosen, since all other processes are $CO_2$-free.

The rated power is 500 MW thermal (coal).

The cost of electricity is stated with and without CCS for comparison. The case without CCS accounts for penalties on $CO_2$ emission in the form of $CO_2$ emission certificate costs.

**Table 35: Calculation of capital expenditure for coal gasification (with CCS)**

| **Component** | ***Quantity*** | ***Unit*** | ***Price/Unit*** | ***Total*** |
|---|---|---|---|---|
| Advance Supercritical Boiler 500 MW (coal) | 1 | plant | incl. | |
| Steam turbine | n/a | unit | incl. | |
| Condenser | n/a | unit | incl. | |
| (ESP) Electrostatic Precipitator + (FGD) Flue-gas Desulfurized | n/a | unit | incl. | |
| Pumps | n/a | unit | incl. | |
| MEA (Monoethanolamine) storage | n/a | unit | incl. | |
| Amine regenerator | n/a | unit | incl. | |
| CO2 scrubber | n/a | unit | incl. | |
| CO2 compressors | n/a | unit | incl. | |
| Cooling tower | n/a | unit | incl. | |
| Absorber (consume grate space) | n/a | unit | incl. | |
| DeNOxPlant | n/a | unit | incl. | |
| Blower for flue gas | n/a | unit | incl. | |
| **Capital expenditure** | I | | | 750.000.000 € |

Table 36 indicates the costs for the production of electricity with coal gasification as 0,07 €/kWh without CCS and as 0,14 €/kWh with CCS. In [Prieur 2008] the cost of electricity production and co-production of electricity and hydrogen are shown in Table 44. As the described process in Table 36 is electricity production, only this could be compared. [Prieur 2008] states the costs for electricity as 0,055 €/kWh without CCS and as 0,061 €/kWh with CCS. While the costs without CCS are in the same range and the difference could be explained with different coal costs (29 €/ton in [Prieur 2008] and 42 €/ton in this case) the costs with CCS are not. One reason for the large difference of 0,069 €/kWh might be the completely different estimate for the $CO_2$ disposal costs. [Prieur 2008] estimated 3,93 €/ton for the transport and 2,14 € as storage costs but in the case which is stated below the total disposal costs are 238,00 €/ton $CO_2$. Another interesting difference is, that only this case included a penalty of 21,00 €/ton $CO_2$ for $CO_2$ emissions (total and the rest after CCS, respectively).

**Table 36: Costs for the provision of energy: coal gasification (with CCS)**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| $CO_2$ emissions - penalty | cop_s | | 21,00 | €/t $CO_2$ |
| $CO_2$ disposal costs | cod_s | | 238,00 | €/t$CO_2$ |
| coal costs | c_s | | 42,00 | €/t |
| Truck size | tr_s | | 25,00 | t/per truck |
| transport costs | t_s | | 1,00 | €/km |
| electricity costs | e_s | | 70,00 | €/MWh |
| water costs | w_s | | 1,45 | €/m³ |
| amine costs | am_s | | 1.635 | €/t |
| labour cost | l_s | | 50 | €/h |
| availability | ava | | 83 | % |
| full load hours | f_l | | 8.041 | h/a |
| Interest rate | i | | 10 | % |
| Depreciation period | t_s | | 30 | a |
| Annuity factor | a | $i * (1 + i)^t / ((1 + i)^t - 1)$ | 0,11 | |
| **Specific consumption** | | | | |
| plant electricity requirement | p_e_r | | 7 | % |
| CCS energy requirement | CCS_e_r | | 20 | % |
| coal consumption | c | | 69,23 | t/h |
| amine consumption | am | | 1,40 | t/h |
| water consumption | w | | 1.269,35 | $m^3$/h |
| steam (strip $CO_2$ from solvent) | st | | 3 | GJ/ t $CO_2$ |
| Flue gas desulphurisation (FGD) waste | FGD_w | | 5,80 | t/h |
| **Basic data** | | | | |
| Plant net output | P_out | | 500.000 | kW |
| net plant output with $CO_2$ capture | P_out_CCS | P_out * ((100 - CCS_e_r) / 100) | 400.000 | kW |
| coal consumption | C | c * f_l | 556.640,08 | t/a |
| electricity consumption | E_c | p_e_r * P_out * f_l / 1000 | 281.435,00 | MWh/a |
| Water consumtion | W | w * f_l | 10.206.861 | m³/a |
| amine consumption | AM_c | am * t_l | 11.257 | |
| coal quality | C_q | | 26 | MJ/kg |
| $CO_2$ emissions | $CO_2$_em | C * 2 | 1.113.280,17 | t$CO_2$ /a |
| $CO_2$ capture efficiency | $CO_2$_eff | | 87,50 | % |
| $CO_2$ emissions after capture | $CO_2$_em_ac | $CO_2$_em - $CO_2$_cap | 139.160,02 | t$CO_2$ /a |
| $CO_2$ captured | $CO_2$_cap | $CO_2$_em * $CO_2$_eff / 100 | 974.120,15 | t$CO_2$ /a |
| Transport range | r | | 300 | km |
| Electricity production | Ep | P_out_CCS * f_l / 1000 | 3.216.400 | MWh/a |
| capital expenditure | I | | 750.000.000 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 79.559.436,19 | €/a |
| coal costs | ACs | C * c_s | 23.378.883,54 | €/a |
| coal delivery costs | CDc | r * t_s * (C / tr) | 6.679.681,01 | €/a |
| electricity costs | AE | E_c * e_s | 19.700.450,00 | €/a |
| water costs | AW | W * w_s | 14.799.949,02 | €/a |
| amine costs | AAM | AM_c * am_s | 18.405.849,00 | €/a |
| labour costs | L | l_s * f_l * 120 * (ava/100) | 40.044.180 | €/a |
| annual penalty for CO2 emissions **without** CCS | AP | $CO_2$_em * cop_s | 23.378.883,54 | |
| annual $CO_2$ disposal costs | ADc | $CO_2$_cap * cod_s | 231.840.595,06 | €/a |
| penalty for $CO_2$ emissions **with** CCS | APccs | $CO_2$_em_ac * cop_s | 2.922.360,44 | €/a |
| total annual costs **without** CCS | ACo | AN+ACs+CDc+AE+AW +AAM+L+AP+ADc+APccs | 225.947.312,29 | €/a |
| total annual costs **with** CCS | ACoccs | ADc+APccs+ACo-AP | 437.331.384,26 | €/a |
| **Specific costs for 500 MW Coal Boiler with CCS** | | | | |
| Costs of electricity production **without** CCS | | ACo / Ep | 70,25 | €/MWh |
| Costs of electricity production **without** CCS | | ACo / Ep / 1000 | 0,07 | €/kWh |
| Costs of electricity production **with** CCS | | ACoccs / Ep | 135,97 | €/MWh |
| Costs of electricity production **with** CCS | | ACoccs / Ep / 1000 | 0,14 | €/kWh |

## 3.3 Gas Producing Processes

In gas producing processes a gas mixture is produced that can then be used to produce hydrogen in a reforming step. Two processes are chosen here that are run on biomass (the process for coal gasification has been described in Section 3.2.7, albeit integrated into electricity production).

Biomass fermentation uses agricultural or food processing wastes or sewage to produce a mixture of methane and carbon dioxide (with minor contributions of mainly $N_2$ and $H_2S$), saturated with water. The mixture usually is in the range of 70:30 to 60:40 of $CH_4$ to $CO_2$.

Gasification produces a synthesis gas (syn-gas) from biomass, especially lignine-rich substrates, and wastes with a varying amount of mainly carbon monoxide and hydrogen (also including $N_2$, $CO_2$, $CH_4$ and minor pollutants). The gas has to be cleaned from particles, tar and a variety of salts and corrosive agents that regularly accompany gasification processes.

Through gas clean-up, reforming and shift reactions (cf. Section 3.1.1), with or without carbon capture and sequestration (CCS) technologies, the yield and purity of hydrogen is increased to a commercially viable level.

It has to be noted, that the 'Gas Producing Process models' presented here are representative of the calculation scheme. They use 'typical' values in the tables, but in no way are meant as predictions of actual or future (hydrogen) prices.

### 3.3.1 Biomass Fermentation

Fermentation substrates include manure and agricultural products ('energy crops') [BFL 2006], [GenCell]. The following table uses a mixture of these two. Industrial applications of biomass fermentation also include sewage and food residues (in food processing plants) where the disposal of the waste can actually also generate income for the fermentation plant. This case is not investigated here due to the very individual character of the relevant contracts. An increase of use of wastes may also invert the situation so that the fermentation plant would have to buy the substrates.

**Table 37: Calculation of capital expenditure for biomass fermentation**

| **Component** | ***Quantity*** | ***Unit*** | ***Price/Unit*** | ***Total*** |
|---|---|---|---|---|
| **Fermantation Plant 80 $kW_{el}$** | 1 | plant | incl. | |
| storage | n/a | unit | incl. | |
| drying room | n/a | unit | incl. | |
| pumps | n/a | unit | incl. | |
| biogas reactor | n/a | unit | incl. | |
| tank for rye&corn | n/a | unit | incl. | |
| tank for manure | n/a | unit | incl. | |
| purification | n/a | unit | incl. | |
| biogas engine | n/a | unit | incl. | |
| | | | | |
| **Capital expenditure** | | | | 240.000 € |

**Table 38: Costs for the provision of energy: biomass fermentation**

| | Abbreviation | Formula | Numerical Value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| electricity costs | e_s | | 0,06 | €/kWh |
| rye & corn costs | r&c_s | | 100 | €/t |
| water costs | w_s | | 1,45 | €/m³ |
| labour costs | l_s | | 50 | €/h |
| chemical reactor volume | rv | | 424 | $m^3$ |
| residence time | rt | | 60 | days |
| storage | st | | 2,9 | kg/$m^3$*day |
| temperature | t | | 38 | $^0C$ |
| substrat temperature | s_t | | 12 | $^0C$ |
| full load hours | f_l | | 7500 | h/a |
| methane quality | q | | 35897 | kJ/$m^3$ |
| Interest rate | i | | 10 | % |
| Depreciation period | T | | 25 | a |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T - 1)$ | 0,11 | - |
| **Specific consumtion** | | | | |
| Substrat: pig manure | S_p_m | | 0,0597 | kg/s |
| Substrat: corn | S_c | | 0,0207 | kg/s |
| Substrat: rye | S_r | | 0,0086 | kg/s |
| water consumption | w | (S_p_m + S_c + S_r) * 0,09 * 3600 | 29 | kg/h |
| fuel consumption | f | (S_p_m + S_c + S_r) * 3600 | 321 | kg/h |
| **Basic data** | | | | |
| electricity consumption | E_c | | 250.000 | kWh |
| water consumption | W_c | f_l * w / 1000 | 216,42 | m³/a |
| fuel consumption | F_c | f * f_l | 2.404,71 | t/a |
| rotor electrical efficiency | R_e_eff | | 32 | % |
| rotor thermal efficiency | R_th_eff | | 39 | % |
| Annual gas production | A_g_p | F_c * 145 | 348.683,21 | $m^3$/a |
| methane content | M_c | | 17,5 | % |
| Annual methane production | A_m_p | A_g_p * M_c / 100 | 61.020 | $m^3$/a |
| Annual electricity production | A_e_p | (A_m_p *q) / 3600 | 608.450 | $kWh_{el}$/a |
| Annual heat production | A_h_p | A_e_p + 0.15 * A_e_p | 699.717 | $kWh_{th}$/a |
| capital expenditure | I | | 240.000,00 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 26.440,34 | €/a |
| Annual rye & corn costs | R&C_c | ((S_c + S_r) / 1000) * f_l * 3600 * r&c_s | 79.281,18 | €/a |
| Annual electricity cost | AE | E_c * e_s | 15.000,00 | €/a |
| Annual water cost | AW | W_c * w_s | 313,81 | €/a |
| Total operating costs | K | R&C_c + AE + AW | 94.594,99 | |
| total annual costs | AK | AN + K | 121.035,33 | €/a |
| **Specific costs for Fermentation Plant** | | | | |
| Cost of electricity | | AK / A_e_p | 0,20 | €/$kWh_{el}$ |
| Cost of electricity (if costs shared 70% el to 30 % th) | | AK * 0,7 / A_e_p | 0,14 | €/$kWh_{el}$ |
| Cost of heat ( if costs shared 70% el to 30% th) | | AK * 0,3 / A_e_p | 0,05 | €/$kWh_{th}$ |

### 3.3.2 Biomass Gasification

Gasification substrates usually are limited to those not fermentable, for instance wood (and wood residues), straw, dried pulp etc., i.e. lignite-rich substrates (see reference [BTG]). Other sources are household and industrial wastes, especially those including plastic residues. In the gasification process these can be converted to syngas. Waste processing regularly requires more involved gas clean-up to take care of the very corrosive components (Cl, Na, S, Ph etc.).

**Table 39: Allocation of land and fence for biomass gasification plant**

| | Area (baseplate) | Proportion land | Proportion fence |
|---|---|---|---|
| **A Gasifier plant** | | | |
| Gasiefier | n/a | n/a | n/a |
| Baseplate (sealed area, concrete)) | 0,00 m² | *0,00 m²* | *0,00 m* |
| Land in total | 2.5 ha | | |
| Fence incl. gate | 0.5 ha | | |
| **Subtotal:** | 3 ha | | |

| **Biomass plantation** | n/a | n/a | n/a |
|---|---|---|---|
| | 14000 ha | | |

**Table 40: Calculation of capital expenditure for biomass gasification**

| **Component** | ***Quantity*** | ***Unit*** | ***Price/Unit*** | ***Total*** |
|---|---|---|---|---|
| Gasifier plant 30 MW | 1 | plant | 93.700.000,00 € | 93.700.000 € |
| Biomass handling & drying facilities | n/a | unit | incl. | |
| Shell biomass gasiefier (50% LHV effic.) | n/a | unit | incl. | |
| Air separation unit (ASU) | n/a | unit | incl. | |
| Cool & cleanup, CO shift, PSA facilities | n/a | unit | incl. | |
| Piping, distribution, installation, miscellaneous | n/a | unit | incl. | |
| | | | | |
| Land | n/a | m² | incl. | |
| therefrom area with potentially explosive atmosphere | | m² | incl. | |
| Baseplate | n/a | m² | incl. | |
| Fence incl. gate | n/a | m | incl. | |
| | | | | |
| **Subtotal** | | | | 93.700.000 € |
| | | | | |
| Project planning costs | 5 | % | 93.700.000,00 € | 4.685.000 € |
| | | | | |
| **Capital expenditure I** | | | | 98.385.000 € |

**Table 41: Costs for the provision of energy: biomass gasification**

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Electricity costs | s | | 0,035 | €/kWh |
| Gasifier power | p | | 30 | MW |
| Transport | t | | 1,0 | €/km |
| Truck size | tr_s | | 25,00 | t/per truck |
| Biomass costs | bk | | 41 | €/ t bone dry |
| Full load hours | h | | 7500 | h |
| Interest rate | i | | 9,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | i * (1 + i)T / ((1 + i)T-1) | 0,124 | - |
| **Specific consumption** | | | | |
| Biomass consumption | bc | p / wm | 1,76 | kg/s |
| Hourly biomass consumption | Hbc | Abc / h | 6,35 | t/h bone dry |
| **Basic data** | | | | |
| Electricity consumption | m | | 219.360,00 | kWh |
| Annual Biomass consumption | Abc | bc * 3600 * h / 1000 | 47.647,06 | t/a |
| Annual air consumption | Aac | Abc * 1.5 | 71.470,59 | t/a |
| Biomass quality | wm | | 17,00 | MJ/kg |
| Syngas density | q | | 1,20 | $kg/m^3$ |
| Range | r | | 400 | km |
| Hourly syngas production | Hsg | bc + 1.5 * bc | 4,41 | kg/s |
| Annual syngas production | $SG_{[t]}$ | Hsg * 3600 * h / 1000 | 119.117,65 | t/a |
| Average hydrogen production | Ahp | $SG_{[t]}$ * 0.1 | 11.911,76 | t/a |
| Syngas quality | Qs | | 6 | MJ/kg |
| Annual syngas production | $SG_{[kWh]}$ | $SG_{[t]}$ * 1000 * QS / 3,6 | 198.529.411,76 | kWh |
| Capital expenditure | I | | 98.385.000,00 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 12.205.533,17 | €/a |
| Power costs | S | s * m * 365.5 | 2.806.162,80 | €/a |
| Biomass costs | FK | bk * Abc | 1.953.529,41 | €/a |
| Transport costs | TR | r * t * round up ((Abc/tr_s);0) | 762.400,00 | €/a |
| Fixed operating costs | W | I 0.05 | 4.919.250,00 | €/a |
| Total operating costs | K | S+FK+TR+W | 10.441.342,21 | €/a |
| Total annual costs | AK | AN + K | 22.646.875,38 | €/a |
| **Specific costs for Gasifier** | | | | |
| Costs of Syngas production | | AK / ($SG_{[t]}$ * 1000 / q) | 0,228 | €/Nm³ |
| Costs of Syngas production | | AK / $SG_{[kWh]}$ | 0,114 | €/kWh |
| Costs of Syngas production | | AK / $SG_{[t]}$ | 190,12 | €/t |

The costs for syn-gas from biomass gasification are 0,11 €/kWh, as stated in Table 41, which is more than double the amount indicated in [Prieur 2008] Table 53. As [Prieur 2008] did not indicated the Power level, the lifetime or the system costs, it is not possible to compare these results. The focus of this report is on the model and not on the costs itself, which is why no further analysis was mode of the references given in [Prieur 2008].

**Table 42: Calculation of capital expenditure for biogas reformer**

| **Component** | ***Quantity*** | ***Unit*** | ***Price/Unit*** | ***Total*** |
|---|---|---|---|---|
| Reformer plant (reference 30 t/day) | 1 | plant | 25.000.000,00 € | |
| Capacity (t/day) | 10 | | | |
| Reformer plant (10 t/day) | 1 | plant | 12.932.046 € | 12.932.046 € |
| $H_2$ compressor 23-80 barg (2 x 100% capacity for 10 t/day) | 2 | unit | 1.000.000 € | 1.000.000 € |
| Piping, distribution, installation, miscellaneous H2 | n/a | | incl. | |
| | | | | |
| Land | 2.500,00 | m² | incl. | |
| Fence incl. gate | n/a | m | incl. | |
| | | | | |
| Off-sites (tie-in, NG dispenser, control room…) | n/a | % | incl. | |
| | | | | |
| **Subtotal** | | | | 13.932.046 € |
| | | | | |
| Project planning costs | 5 | % | 13.932.046,45 € | 696.602 € |
| | | | | |
| **Capital expenditure I** | | | | 14.628.649 € |

## Table 43: Costs for the provision of energy: biogas reformer

| | Abbreviation | Formula | Numerical value | Unit |
|---|---|---|---|---|
| **Economic boundary conditions** | | | | |
| Syngas costs | sg_s | | 0,13 | €/kWh |
| Electricty costs | e_s | | 0,035 | €/kWh |
| Feed Water : steam generation system | w_s | | 2,6 | €/m³ |
| Export steam price | es_s | | 13 | €/t |
| Cooling water | cw_s | | 0,017 | €/m³ |
| Nitrogen | n_s | | 0,09 | €/Nm³ |
| Instrument Air | ar_s | | 0,015 | €/Nm³ |
| Labor hour cost | l_s | | 50 | €/h |
| Full load hours | f_l | | 7.500 | h/a |
| Interest rate | i | | 9,00 | % |
| Depreciation period | T | | 15 | years |
| Annuity factor | a | $i * (1 + i)^T / ((1 + i)^T-1)$ | 0,124 | - |
| | | | | |
| **Specific Consumption** | | | | |
| Syngas | sg | | 52000,0 | kWh/t $H_2$ HHV |
| Export steam | es | | 6,5 | t/t $H_2$ |
| Feed Water : steam generation system | w | | 16,9 | m³/t $H_2$ |
| Electricity : Instrument and Lightning | Ein | | 12,0 | kWh/t $H_2$ |
| Electricity : Aero cooler + Fans (flue gas and Air) | Eaer | | 100,0 | kWh/t $H_2$ |
| Electricity : Water pump | Epum | | 48,0 | kWh/t $H_2$ |
| Electricity : $H_2$ compression | Ecom | | 590,0 | kWh/t $H_2$ |
| Cooling water | cw | | 68,0 | $m^3$/t $H_2$ |
| Nitrogen | n | | 2,6 | $Nm^3$/t $H_2$ |
| Instrument Air | ar | | 21,0 | $Nm^3$/t $H_2$ |
| **Basic data** | | | | |
| Power input | Pin | 10 / 24 * 1000 * 39,41 | 16.421 | kW HHV |
| Syngas | SG | sg * $E_{H2[t]}$ | 163 | GWh |
| Export steam | ES | es * $E_{H2[t]}$ | 20.277 | t/a |
| Feed Water : steam generation system | W | w * $E_{H2[t]}$ | 52.808 | m³/a |
| Electricity : ISBL comsumption | Eisbl | (Ein+Ear+Epum) * $E_{H2[t]}$ /1000 | 500 | MWhe/a |
| Electricity : $H_2$ compression | E_com | Ecom * $E_{H2[t]}$ /1000 | 1.844 | MWhe/a |
| Electricity consumption | E_c | Eisbl + E_c | 2.344 | MWhe/a |
| Cooling water | CW | cw * $E_{H2[t]}$ | 212.500 | m³/a |
| Nitrogen | N | n * $E_{H2[t]}$ | 8.125 | Nm³/a |
| Instrument Air | AR | ar * $E_{H2[t]}$ | 65.625 | Nm³/a |
| Annual $H_2$ Production | $E_{H2[t]}$ | 10/24 * f_l | 3.125 | t $H_2$/a |
| Annual $H_2$ Production | $E_{H2[Nm^3]}$ | 10/0.08988/24*1000*f_l | 34.768.580 | Nm³/a |
| Annual $H_2$ Production | $E_{H2[kWh]}$ | $E_{H2[Nm^3]}$ * 3.55 | 123.428.460 | kWh/a HHV |
| Capital expenditure | I | | 14.628.649 | € |
| **Annual costs** | | | | |
| Annuity | AN | I * a | 1.814.814 | €/a |
| Syngas costs | ASG | SG * 10^6 * sg_s | 21.094.615 | €/a |
| Export steam Income | ES_in | ES * es_s | 263.604 | €/a |
| Water costs | AWs | W * w_s + CW * cw_s | 140.913 | €/a |
| Electricity | AE | E_c * 1000 * e_s | 82.031 | €/a |
| Other consumptions | AC | N * n_s + AR * ar_s | 1.716 | €/a |
| Costs for service and maintenance | AS | I * 0.03 | 438.859 | €/a |
| Labor cost | AL. | l_s * 24 / 10 * $E_{H2[t]}$ | 375.000 | €/a |
| Miscellaneous costs (insur., taxes...) | AM | I * 0.02 | 292.573 | €/a |
| Total operating costs | K | ASG+AWs+AE+AC+AS+AL.+AM-ES_in | 22.162.103 | €/a |
| Total annual costs | AK | AN+K | 23.976.917 | €/a |
| **Specific costs for Reformer** | | | | |
| Costs of $H_2$ production | | | 0,690 | €/Nm³ |
| Costs of $H_2$ production | | | 0,194 | €/kWh |
| Costs of $H_2$ production | | | 7672,613 | €/t |

# 4. Conclusions

The work presented here was aimed at establishing transparent spreadsheets for calculating the cost of hydrogen produced from a variety of sources:

- By electricity, considering the cost of the electricity production and electrolysis unit(s)
- By conversion of gases to hydrogen (steam methane reforming), and
- By direct production of hydrogen from biomass and nuclear energy.

The intention of the report is not to present yet further estimates of current or future hydrogen costs, but to elaborate the calculation procedures, following the method described in [Linnemann 2007]. Therefore the figures used in the tables are largely of exemplary character without a deep analysis of costs of services and components (other than derived from a variety of publicly available sources). Instead, we intended to describe the calculation process in such a transparent way, that users can apply the models to any cost database they might choose to use now or in the future. This eliminates the problem of comparability and future validity many cost calculations and predictions offer, since they are in their majority based on cost established for a singular situation at a given point in time and cannot easily be converted to a different layout, economic consideration or market situation, once new technical and economical details arise.

Nevertheless, the figures produced here have been compared with other Roads2HyCom output, namely the report [Prieur 2008]. Although based on a completely different database (using data from DoE studies from the year 2002), the data are in general agreement. This proves the robustness of the cost models in most cases, but also highlights the influence basic assumptions and estimates have on the cost calculations in those few cases where agreement is poor.

Many of the cost elements used in the tables are not readily derived from published data (especially those referring to large scale power plants). Generic cost estimates will therefore naturally fall short of any predictive value. The calculation schemes presented here, though, are a tool that can be applied to the hydrogen production pathways presented as soon as more reliable data are available. They can also be used to compare production costs cited in other sources with own data and assumptions.

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