Cost Analysis of Hydrogen Infrastructure in Europe

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Abstract:

This paper gives an outlook on the cost development of hydrogen as a fuel for public transport in Europe. The cost predictions are calculated using a software model implemented within the GaBi 4 Life Cycle Assessment (LCA) software.

In the first part a brief overview on hydrogen production methods is given. Advantages and disadvantages of the currently major methods of steam reforming and electrolysis are considered.

The next section is dedicated to cost prediction methods used in the chemical industry. Different cost prediction methods are surveyed considering the necessary and available data, the level of detail and the accuracy.

In the third chapter the cost model applied in this study is described and the equations and assumptions it is based on are explained. The theoretic background of this model was derived from some of the cost prediction methods of the chemical industry mentioned above and other effects like the learning-curve effect.

The determination of the scenarios and boundary conditions which are to be considered is vital to the obtained results. The assumptions and scenarios are based on literature and information obtained during talks with experts from various fields such as local traffic companies, bus manufacturers, hydrogen production plant manufacturers and others.

At last the obtained results are illustrated and discussed and a short outlook on future developments is given.

1 Principles of hydrogen production

1.1 Electrolysis[1,2]

In about 70 years the basic concept has not changed. However, the conversion efficiency has been improved from about 59 – 63% in the 1970s to about 68 – 76% now, based on the lower heating value of hydrogen.

Basically there are two types of industrial electrolysers: the unipolar (tank-type) and the bipolar (filter-press) type.

A third type is based on the Solid Polymer Electrolyte (SPE) technology, which is a registered trademark owned by Hamilton Standard, a division of United Technologies Corp., but was originally introduced by General Electric in the 1970s.

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[1] Hoffmann, Peter: Tomorrow's Energy: Hydrogen, Fuel Cells, and the Prospects for a Cleaner Planet, The MIT Press 2001

[2] Bailey, James and Fritz Ullmann 2001: Ullmann's Encyclopedia of Industrial Chemistry 1998 (electronic release) – Hydrogen Production. Weinheim: Wiley-VCH.

Steam reforming[3,4]

Steam reforming has been the most efficient economical and practical technique available for conversion of light hydrocarbons to hydrogen and hydrogen/carbon monoxide mixtures for several decades. Raw materials used range from natural gas, methane, and methane containing refinery gases through various combinations of light hydrocarbons including ethane, propane, butane, pentane, light naphtha and heavy naphtha.

1.2 Other production methods

Other production methods such as high temperature electrolysis, splitting steam, thermo-chemical water splitting, Kværner process, partial oxidation (POX), coal gasification, photo-electrochemical splitting, microbiological splitting and direct high-temperature solar splitting are playing a minor role in hydrogen production.

2 Cost prediction methods in the chemical industry

For the cost prediction model it is assumed that the hydrogen plants are highly automated respectively manual labour to operate the plant is mainly included in the price of the plant/service package. Therefore the main cost drivers of the produced hydrogen are direct cost and fixed capital cost. The other costs and their estimation methods are not discussed in this paper.

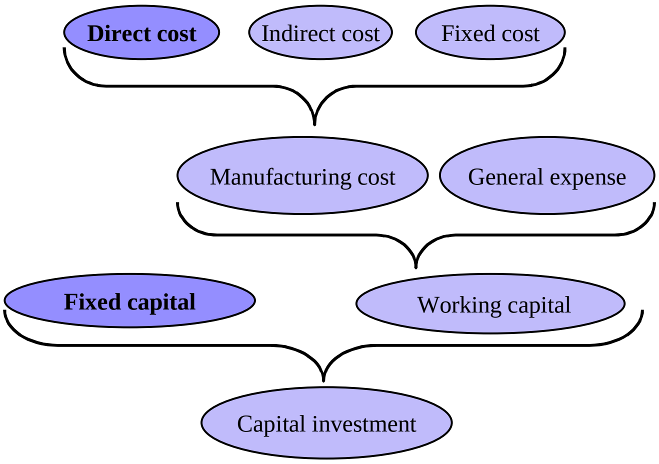

Figure 1: Cost composition

2.1 Direct cost

The direct cost comprise raw materials, energy and utilities, labour, supervision, maintenance, plant supplies, royalties and patents. In this case only the raw materials, energy and utilities are of major interest.

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[3] Minet, R. G., and Olesen, O.: technical and Economic Advances in Steam Reforming of Hydrocarbons; in Smith, W. Novis and Santangelo, Joseph G.: Hydrogen: Production and Marketing, American Chemical Society. ACS symposium series; 116. 1980

[4] Yürüm, Yuda: Hydrogen Production Methods, in Yürüm, Yuda: Hydrogen Energy System, Production and Utilization of Hydrogen and Future Aspects, Kluwer Academic Publishers, Dordrecht 1995

Raw materials, energy and utilities

As cost for raw materials and for energy it is common sense to takethe fair market value of these goods into account. Since they depend on various factors it is hard to predict future developments. As stated below values from literature are used in this study.

The calculated amounts of utilities should be increased by 25 to 50 per cent to allow for building and service needs, losses, and contingencies.

2.2 Fixed capital estimate

There are several approaches to estimate the fixed capital cost:

Fully detailed

For the most accurate estimate a lot of exact data is required. If the data of the material cost, labour rates, efficiencies, man-hour calculations, insurance, tax and duty information, site surveys and soil investigation and field expense is available the total cost is calculated by summing up all these[5]:

$$\boxed{I_F = \sum i_c}$$

Equation 1: Summing-up of expenses

where I_F = fixed-capital investment
i_c = all items completely priced

Based on the physical-plant cost

For this method exact data of all the cost assets as of the physical plant which are outlined above are needed. The Engineering and construction cost is then derived from the physical plant cost by multiplying with an equivalent to percentages.[6]

Percentage of equipment cost

For this method only the cost of the purchased equipment has to be known. All other assets composing the physical plant cost are estimated as an equivalent percentage of the purchased-equipment cost.[5] [6]

Lang's factor

The purchased-equipment cost multiplied by a factor derived by Lang gives the fixed capital investment.

Table 1: Lang's Factor for Fixed Capital[6]

Process	Factor
Solid	3.10
Solid-fluid	3.63
Fluid	4.74

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[5] Bauman, H. Carl: Fundamentals of cost engineering in the chemical industry; New York: Reinhold, 1964

[6] Aries, Robert S.; Newton, Robert D: Chemical engineering cost estimation; McGraw-Hill chemical engineering series; New York: McGraw-Hill, 1955

Up-scaling formula

If you know the fixed-capital cost of a plant for the same process but of different capacity you can scale up or down these costs using the following formula.

$$\boxed{I_{Fb} = I_{Fa} \cdot \left(\frac{r_{mb}}{r_{ma}} \right)^{0.7}}$$

Equation 2: Up-scaling Formula[6]

where r_{ma} = monthly production rate of plant a
r_{mb} = monthly production rate of plant b
I_{Fa} = fixed-capital investment of plant a
I_{Fb} = fixed-capital investment of plant b

This formula is an adaptation of the **six-tenths factor rule** which is applied for use in estimating equipment cost. However, the power term is not found to be generally about six tenths for estimates of fixed-capital costs of a whole plant.

It is rather dependent on the kind of process. For the average chemical process, the power term will be 0.7, as shown in the equation. If you regard very small installations or processes employing extreme conditions of temperature or pressure, the power term will be between 0.3 and 0.5. For plants consisting of multiple units rather than up-scaled equipment, the term will be 0.8. If you have data for more than one plant size, you can evaluate an individual power term for your process.[6]

Per-unit process cost

The total fixed-capital cost is estimated by the average fixed-capital cost per unit of annual capacity times the annual production rate. The average fixed capital cost per unit of annual capacity must be known already for the chemical you want to produce.

This method is already pretty rough and just makes sense when you have got data for the fixed capital per unit of annual productivity from one of the many publications concerning this matter. It is a very simple linear approach and does not consider economy of scale effects.

Turnover ratio

Aries and Newton are stating the turnover ratio as the ratio of annual sales value to capital investment. When the turnover ratio is known for the process it can be used to calculate the fixed-capital cost by this equation[6]:

$$\boxed{I_F = \frac{S \cdot r_a}{T}}$$

Equation 3: Turnover ratio[5] [6]

where I_F = fixed-capital cost
S = sales value per unit of production
r_a = annual production rate
T = turnover ratio

Like the method before this one is also very coarse and just makes sense for a quick estimation when data of the turnover ratio is easily available already.

3 The cost model

3.1 Cost of building the plants

The different cost of building the steam reformer plant as well as the electrolyser plant are all accounted for in the price of the plants. To allow for an internal rate of return and to account for changes of the plant price due to change of capacity or number of produced plants a set of adapted equations is used:

The price a 100 Nm³/h steam reformer filling station respectively a 100 Nm³/h electrolyser plant is used as starting point for the calculation of the fixed cost of the plants.

To adapt to other production capacities the up-scaling formula mentioned above is applied.

The experience-curve effect is incorporated in the model by applying a formula derived from the experience-curve effect equation.

To allow for a yearly rate of return on the capital investment a still higher cost has to be assessed, which then has to be allocated to the produced and sold hydrogen. This is done by the annuity methodology.

These calculations are shown in Figure 2 exemplarily for the total fixed capital cost of 10 200Nm^3/h steam reformer plants operating for 20 years.

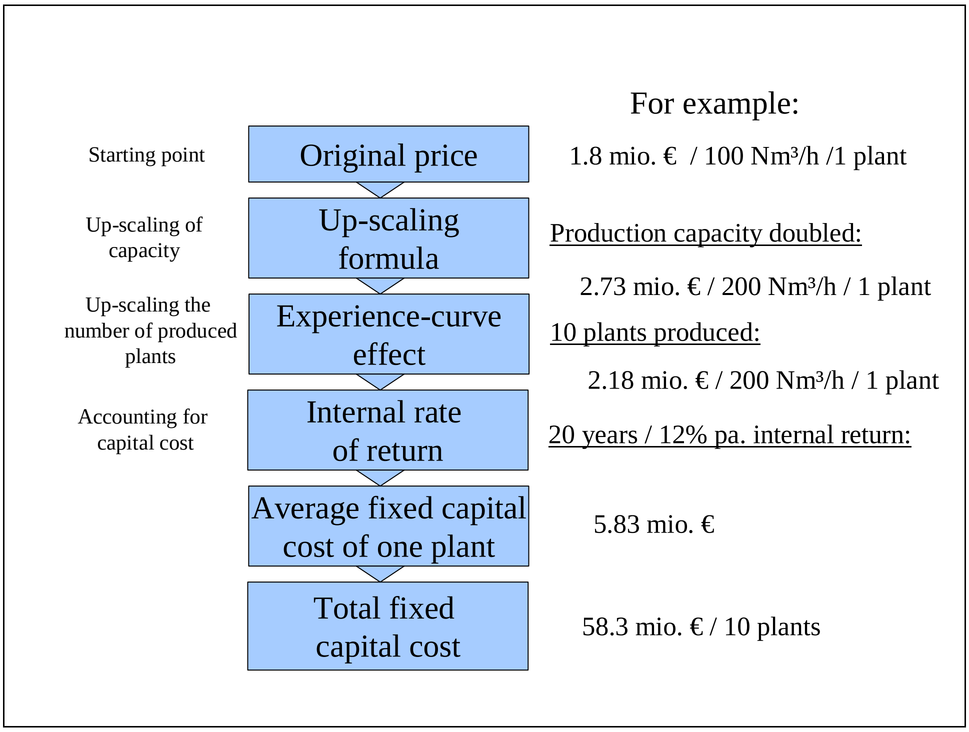

Figure 2: Fixed cost calculation hydrogen infrastructure

Experience-curve effect

The equation for the experience-curve Effect (see Equation 4) describes the development of cost for one plant or unit during the production process. To evaluate the cost of the hydrogen infrastructure the average cost of produced plants is needed instead. So the equation has to be integrated over the number of produced plants (see Equation 6).

$$\boxed{c_t = c_0\left(\frac{X_t}{X_0}\right)^{-a}}$$

Equation 4: Experience-curve effect

where c_t = cost of each unit in period t
c_0 = initial unit cost
X_t = production volume in period t
X_0 = production volume in the first period observed
a = experience coefficient

In our case the production volume of the first period observed is just one plant. That leads to the following equation:

$$\boxed{c_t = c_0 X_t^{-a}}$$

Equation 5: Adapted experience-curve equation

Integration over X_t leads to the following:

$$\boxed{\overline{c} = \frac{c_0(1-a)}{x}[(d_0 + x)^{(1-a)} - d_0^{(1-a)}]}$$

Equation 6: Average plant cost (experience-curve effect)

where $\overline{c}$ = average cost of a plant
c_0 = initial cost of the first plant
x = number of produced plants
a = experience coefficient
d_0 = offset parameter for correction purpose

Equation 6 stands for an integration of the experience-curve from d_0 to (d_0+x). As the experience-curve itself delivers the value of the initial cost at the point $X_t=1$, the Integrated function for the average plant cost should lead to the same result for x=1. Integration from 0 to 1 would lead to a much higher value, as integration from 1 to 2 would deliver a value that is too low. d_0 has to be set to a value between 0 and 1 so that $\overline{c} = c_0$ for x = 1. In other words it has to be chosen in such way that for a given experience coefficient a the following equation is true.

$$\boxed{(1-a)[(d_0 + 1)^{(1-a)} - d_0^{(1-a)}] = 1}$$

Equation 7: Finding the offset parameter

where d_0 = offset parameter
a = experience coefficient

In this case for a factor of cost decrease of 0.9 a offset parameter of about 0.55 seems suitable.

The experience coefficient is calculated from the factor of cost decrease with Equation 8.

$$\boxed{a = -\frac{\log p}{\log 2} = -lb\ p}$$

Equation 8: Experience coefficient[7]

where a = experience coefficient
p = factor of cost decrease

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[7] Gößler, Andreas: Describing and Explaining Experience-Curve Effects Using System Dynamics, POM, Mannheim 2000; http://134.155.60.64/lehrstuhl/mitarbeiter/agroe/ExpCurve.pdf

Internal rate of return

To account for a return of invest the annuity method was chosen. The internal rate of return represents a theoretical yearly revenue. The annuity method is usually used to convert one-time capital expenditures into constant annual amounts. Therefore the following equation is used:

$$\boxed{A = C_0 \frac{i(1+i)^n}{(1+i)^n - 1}}$$

Equation 9: Calculating annuities

where A = annuity
C_0 = capital expenditure
i = internal rate of return
n = utilization period

To calculate the capital cost over the whole utilization period the annuities are summed up by multiplying the annuity by the number of years of the utilization period.

$$\boxed{C_c = nA = nC_0 \frac{i(1+i)^n}{(1+i)^n - 1}}$$

Equation 10: Capital cost (via annuities)

From all the equations above many parameters can be adjusted to illustrate a defined scenario. To get an better overview these free parameters are listed in the following table:

Table 2: Free Parameters to Assess Fixed Cost

Starting point	capacity of the known filling station [Nm³/h]
	cost of the known filling station [€]
Up-scaling formula	Up-scaled capacity of one hydrogen filling station [Nm³/h]
	Exponent in the equation; varies with the type of process
Experience-curve effect	number of produced hydrogen filling stations [pcs.]
	factor of cost decrease [ ]
Annuity method	utilization period [a]
	Internal rate of return (inflation-adjusted) [%/a]

3.2 Cost of operating the plants

The distinction between dependence on the output and dependence on the operating time was not implemented in the model. Output and Operating time are directly correlated if you assume a constant utilization ratio. Even if that is not the case in reality, the assumption of a constant utilization ratio will not lead to major inaccuracies for three reasons:

- First, because it is not sure if the cost for spare parts is rather related to the operating time than to the output.
- Second, due to the highly automated plants the cost of the staff is very small if not negligible and should probably not be considered as dependant on output nor on operating time at all.
- And third, if there are differences between the dependence on output and operating time they can be corrected by deploying another average utilization ratio.

4 The considered scenarios

Three different scenarios have been investigated. The first one is based on hydrogen production of single plants. Cost reductions of the plant price based on the experience-curve effect or the six-tenths factor rule are not accounted for.

The other two scenarios are considering the situation EU policy is aiming at in 2015. By then 2% (based on the energy content; lower calorific heating value) of the fuel demand in the public transport sector shall be substituted by hydrogen. That leads to 7283 TJ per year which equals 60,689 tons or 675 million Nm³ of hydrogen.[8]

In the following table the parameters are listed which are chosen uniformly for all the scenarios:

Table 3: Uniform parameters

Parameter	**Value**
Internal rate of return [12%]	12
Factor of cost decrease [ ]	0.9
Utilization period [a]	20
Utilization ratio [%]	95
Down time [d/y]	15

A rate of twelve percent is a moderate return. What rate of return should be finally applied depends also on the expectations of the investor.

With most of the observed products showing a factor of cost decrease between 0.7 and 0.8 the assumption of a cost decrease factor of 0.9 seems rather conservative. Instead it is chosen higher to account for the parts of the plants which are not build for the first time. In case of an assembly of standard parts produced on large scale it was proposed to examine the cost decrease for each part separately. But due to the lack of available information this simpler approach had to be chosen.

The stated 20 years utilization period are quite long in comparison with usually only 12 years being accounted for as depreciation period. In fact the steam reformer plant is designed for 100,000 hours run-time which is about eleven and a half years on the basis of continuous operation. Experience on behalf of the plant builders shows that usually it is no problem to achieve a lifetime of even over twenty years if the plant is well-maintained and checked regularly.

In a paper about hydrogen filling stations Valentin[9] assumes a utilization ratio of 75% for small hydrogen filling stations with on-site production. He substantiates this with the waving of demand which has to be counteracted by a higher production capacity and a lower average utilization ratio. In the case of public transport the demand is very stable, because the buses are always taking the same routes consuming more or less the same amount of hydrogen. The

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Assumptions: 520,000 Busses and Coaches in 1999; from: European Union: Energy & Transport in Figures 2003, EU DG Tren;
Bus share: 75,6% from: Kyriakis, Nikolas.A. et al: Methodologies for Estimating Air Pollutant Emissions from Transport – Road Traffic Composition – Deliverable No 16 – Final / Updated Edition, Aristotle University of Thessaloniki, July 1998
26.190 l diesel consumption per bus and year; from own research with transport companies

[9] Valentin, Bernhard: Wirtschaftlichkeitsbetrachtung einer Wasserstoffinfrastruktur für Kraftfahrzeuge Teil1; Fachhochschule München, 2001

plant is planned and designed for those well-known operation conditions. Therefore the utilization ratio of 95% should be achievable.

15 days down time per year is a value stated by Thomas[10] in 1997. This value is also taken into account in the paper of Valentin[9].

The following table shows the parameters which are different for the steam reformer and the electrolyser scenarios but apart from that stay the same in the different scenarios:

Table 4: Different parameters

Parameter	**Value set electrolyser**	**Value set steam reformer**
Capacity of the known filling station	100 Nm^3/h	100 Nm^3/h
Cost of the known filling station	1,5 mio €	1,8 mio €
Cost for maintenance	2.6% of the capital investment	3% of the fixed-capital investment
Cost for insurance	0.15% of the capital investment	0.15% of the fixed-capital investment
Up-scaling factor	0.7	0.6

The initial capacity is the capacity of the base plants. All up-scaling was done on the basis of these plants and their capacities.

The initial cost comprises the hydrogen production including the compression, the storage and the filling station components.

The initial cost is based on values found in literature. Following sources have been found:

Table 5: Literature sources for plant costs

Source	**Investment cost of a electrolyser filling station (100 Nm^3/h)**	**Investment cost of a steam reformer filling station (100 Nm^3/h)**
Valentin[9]	1,54 mio €	2,31 mio €
KIB[11]	1,5 mio €	1,3 mio €
Mean value	1,52 mio €	1,81 mio €

As the statements for the investment cost of the steam reformer are very different it seems a good compromise to take the mean value into account. A sensitivity analysis for this parameter will be found below.

The maintenance cost of 3% of the capital investment for the steam reformer plant is a general assumption in chemical process cost estimation and was confirmed by experts. The value of 2.6% of the investment cost for the electrolyser is based on information of a plant constructor.

1.5% of the capital investment was taken into account for insurance cost. That value is also based on the statements of a plant constructor. It was assumed that there is no big difference concerning the safety between an electrolyser and a steam-reformer. Therefore the cost for insurance should also be very similar.

It was stated above that the power term of the up-scaling formula is dependent on the kind of plant. Though generally 0.6 is contended to lead to good agreement for chemical plants for

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[10] Thomas, C. E. et al: Hydrogen Infrastructure Study Summary, Section 1, U.S. Department of Energy, Office of Transportation Technologies, Prime Contract No. DE-AC02-94CE50389, July 1997

[11] Faltenbacher, M. et al: How to supply fuel cell cars in Stuttgart with hydrogen – a view into the year 2020, Kompetenz + Innovationszentrum Brennstoffzelle, 2003

modular plants, a factor of 0.8 is proposed. Considering that the electrolyser filling station is build of modular parts as the electrolyser itself and maybe the storage as well as of up-scaleable parts as the water purifier, the compressor or transformer 0.7 seems to be a good compromise.

The assumed cost for the electric energy (8.8 – 9.8 Ct/kWh) for the steam reformer plants is taken from a study conducted by the prognos institute[12] on behalf of the german federal ministry for economy and technology. From the same study a mean value of natural gas energy cost of 1,56 Ct/Nm^3 for industrial customers over the next 20 years was deduced. In other sources much higher values where found. It again seemed appropriate to take a mean value.

Table 6: Sources for natural gas costs

Source	Energy cost of natural gas
Prognos-Report[12]	1,56 Ct/kWh (industrial customers)
Other Sources[13] [14](Average)	3,63 Ct/kWh (more than 20000kWh/30000kWh per year)
Mean value	2,60 Ct/kWh

In a report of the Alternative Fuels Contact Group[15] electricity prices of 4, 7 and 10 Ct/kWh have been considered. Accordingly a price of 7 Ct/kWh was assumed in this paper. The chosen price for electric power is therefore below the 8.8 to 9.8 Ct/kWh predicted by the prognos institute.

To show the spread in hydrogen production cost the lower and the higher value of 4 respectively 10 Ct/kWh have both been taken into account. Also for the natural gas the spread is shown by taking into account the values from Table 6 (see Figure 3).

In the calculated hydrogen production costs no taxes have been accounted for.

4.1 Scenarios 1: single small plant

In the first scenario a single 100 Nm³/h electrolyser filling station respectively one 100Nm³/h steam reformer filling station were considered.

4.2 Scenario 2: small plants

Scenario 2 is based on the 2% substitution of the fuel in public transport in 2015 mentioned above. To provide the 675 million Nm³ per year, 846 plants with a production capacity of 100 Nm³/h are needed. The utilization ratio is assumed to be 95%.

4.3 Scenario 3: big plants

Scenario 3 is based on the same hydrogen demand of 675 million Nm³ per year but now the plant size was up-scaled to a production capacity of 600 Nm³/h. That leads to a necessary plant number of 141. The production capacity of 600 Nm³/h was chosen in correspondence to a higher number of busses per fleet. In this case 50 busses per fleet was thought to be a fitting number. Due to unknown consumption values of the busses under real operating conditions this choice of maximum production capacity of the plants has to be checked.

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[12] Prognos AG (Hrsg.): Energiereport 3. Die längerfristige Entwicklung der Energiemärkte im Zeichen von Wettbewerb und Umwelt; Schaeffer-Poeschel Verlag 2000

[13] TWL-Homepage (http://www.twl.de/presse/20020830_1.shtml), 01.06.2004: 3,48 Ct/kWh for a demand of 20.000 kWh/y or more

[14] Stadtwerke Rheine-Homepage (http://www.stadtwerke-rheine.de/extern/swrheine/content.nsf/index/G-Erdgas?opendocument), 01.06.2004: 3,78 Ct/kWh for a demand of 30.000 kWh/y or more

[15] Alternative Fuels Contact Group: Market development of alternative fuels, December 2003

5 Results of the calculations and discussion

Figure 3 shows the total cost per Nm³ hydrogen for the six scenarios. The 100 Nm³/h electrolyser plant produces hydrogen at 74 cent/Nm³. The steam reformer plant leads to 54 cent/Nm³.

In scenario two a number of 846 filling stations has been assumed. This leads to lower fixed capital costs because the cost of the plant is reduced according to the learning-curve effect described above. The manufacturing cost is also going slightly down because the amount estimated for insurance and maintenance is based on the fixed capital cost. But it is a minor effect. In these scenarios a cost of 56 cent/Nm³ hydrogen for the electrolyser plant and 32 cent/Nm³ for the steam reformer plant is calculated.

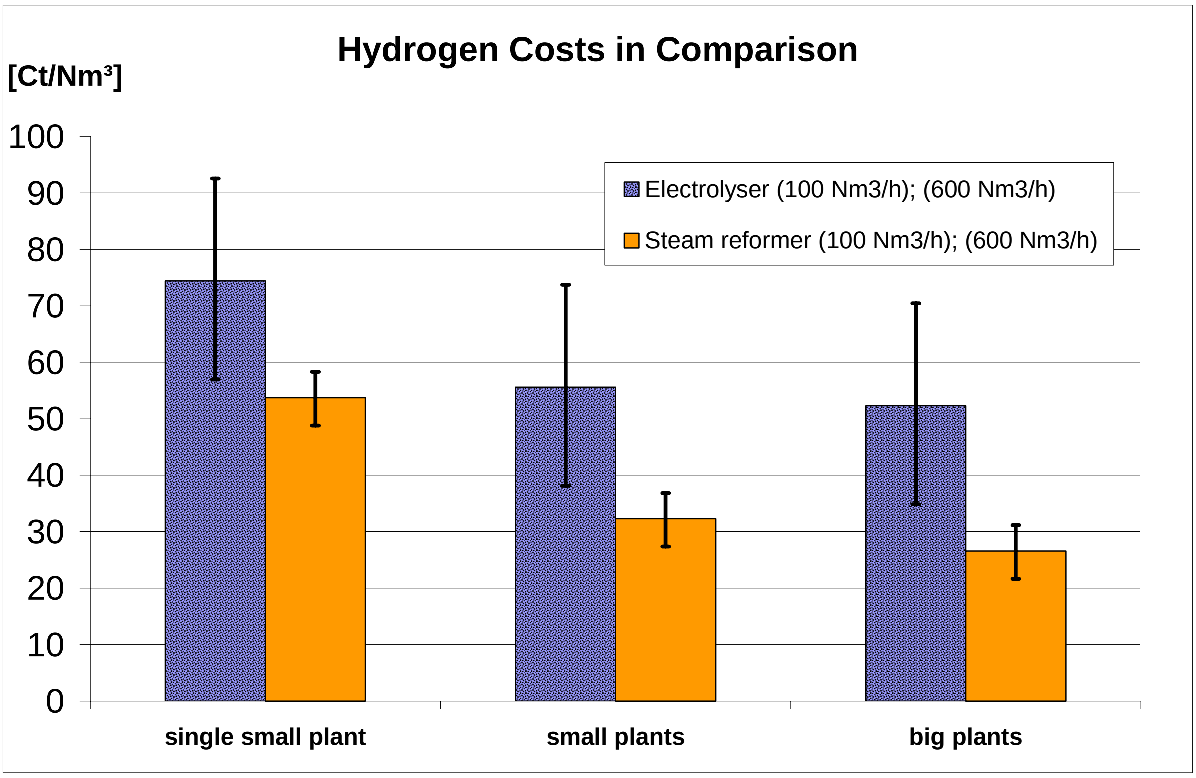

Figure 3: Hydrogen costs in comparison

In scenario three the same total amount of hydrogen demand is assumed but the size of the plants was scaled up to 600 Nm³/h. The experience-curve effect as well as the six-tenths-factor rule are applied. That leads to the cost of 52 cent/Nm³ for the electrolysis and 27 cent/Nm³ for the steam reformer plant.

The black bar shows the variation in hydrogen production cost with regard to the different feed cost.

The cost composition is regarded in the following.

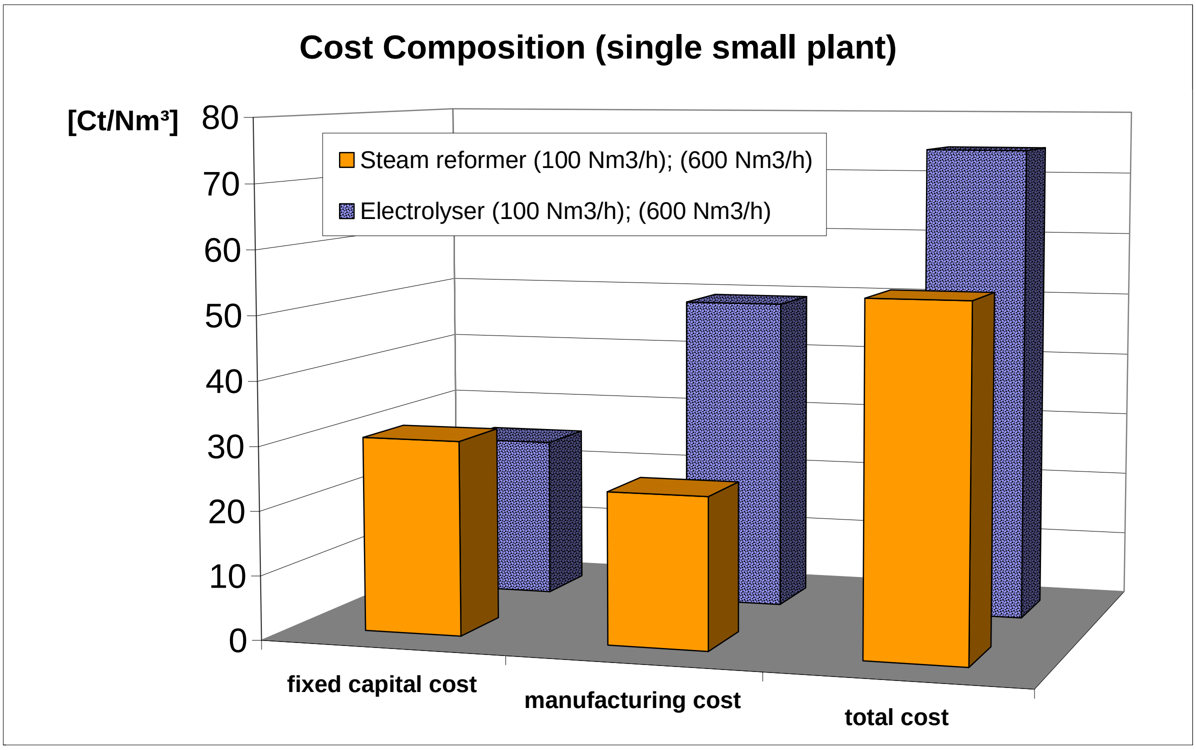

Figure 4: Cost composition for a single small plant

For the electrolyser plant a fixed capital cost of 25 cent/Nm³ (34% of the total cost)arises from the plant cost. The steam reformer plant leads to a fixed capital cost of 30 cent/Nm³ (56% of the total cost) hydrogen.

The manufacturing costs of the steam reformer path are lower than the manufacturing cost for hydrogen via electrolysis. That is because of the different energy cost for natural gas and electric power.

For the hydrogen manufacturing cost 49 cent/Nm³ (66% of the total cost) for the electrolyser is obtained in comparison to 24 cent/Nm³ (44% of the total cost) for the steam-reformer. The total cost already shown in Figure 3 results as sum of the fixed capital cost and the manufacturing cost.

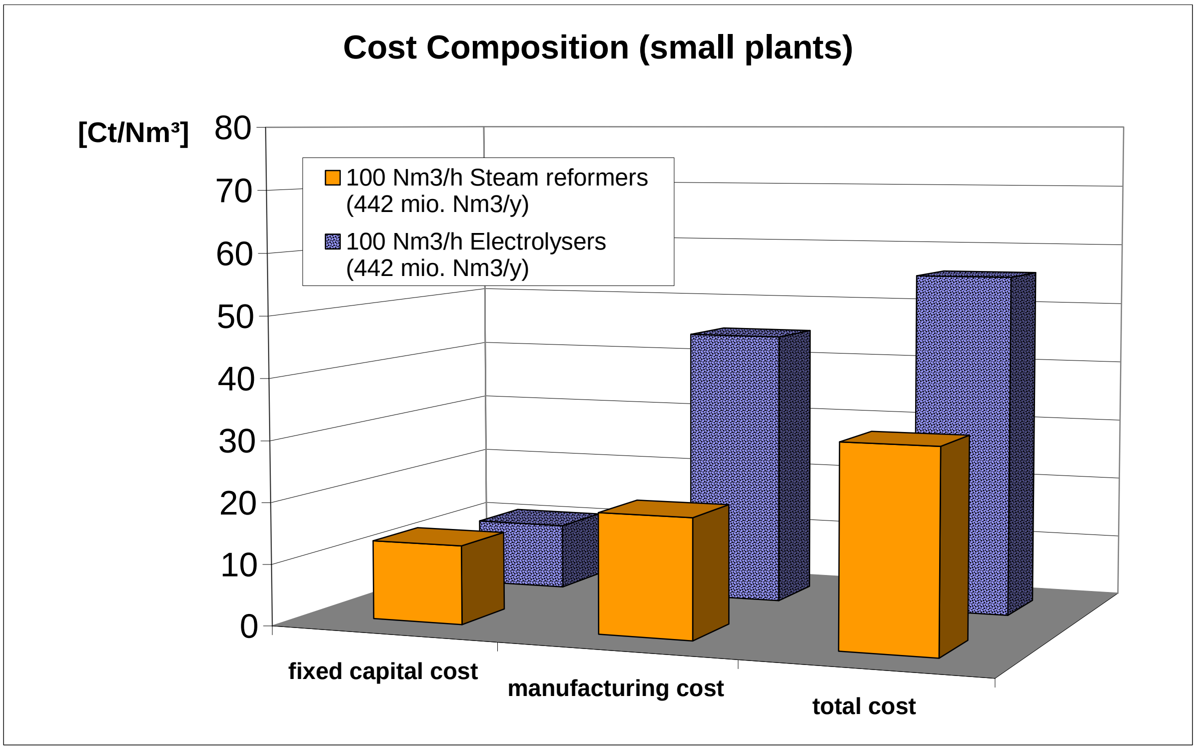

Figure 5: Cost composition for 846 small plants

The cost decrease in scenario 2 results from decreasing plant costs, when plant production is up scaled (Figure 5). In electrolysis the fixed capital cost has a lower share of the total hydrogen production cost, reductions in plant cost do not affect the total hydrogen cost as much as for the steam reforming.

The manufacturing cost for the Nm³ hydrogen from electrolysis is 45 cent/Nm^3 (81% of the total cost) in comparison to 19 cent/Nm^3 (60% of the total cost) for hydrogen from steam reforming.

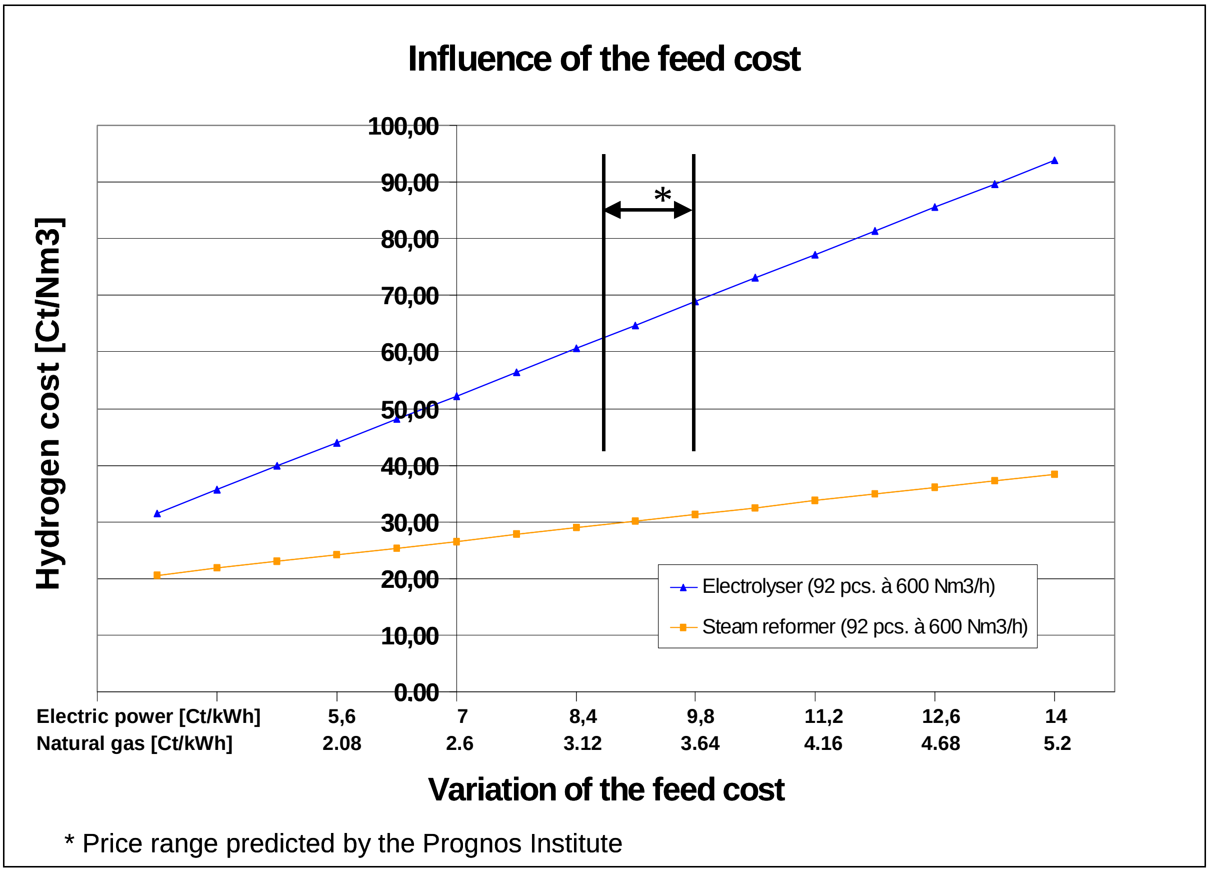

Figure 6: H_2 production cost dependence on the feed cost

The influence of the feed cost on the hydrogen cost is shown in figure 6. Under the ordinate the feed is plotted on which cost the scenario three is based on. To the left and the right the same percentage decrease and increase are plotted The range of the prices for electric power predicted by the Prognos Institute[12] for the period from 1997 to 2020 for industrial customers are marked.

The initial plant cost as the starting point of the calculations of the model is crucial for the result. Figure 7 shows the influence of the estimated cost of the two different small plants (scenario 1) the whole model is based upon. You can see that the effect on the steam reformer is a little bit higher. That is due to the fact, that the share of the fixed capital cost of the hydrogen production cost is higher than for the electrolyser. 0% marks the cost of the filling stations the scenarios were based upon (1,8 mio € for the 100 Nm^3/h steam reformer filling station and 1,5 mio € for the 100 Nm^3/h electrolyser filling station).

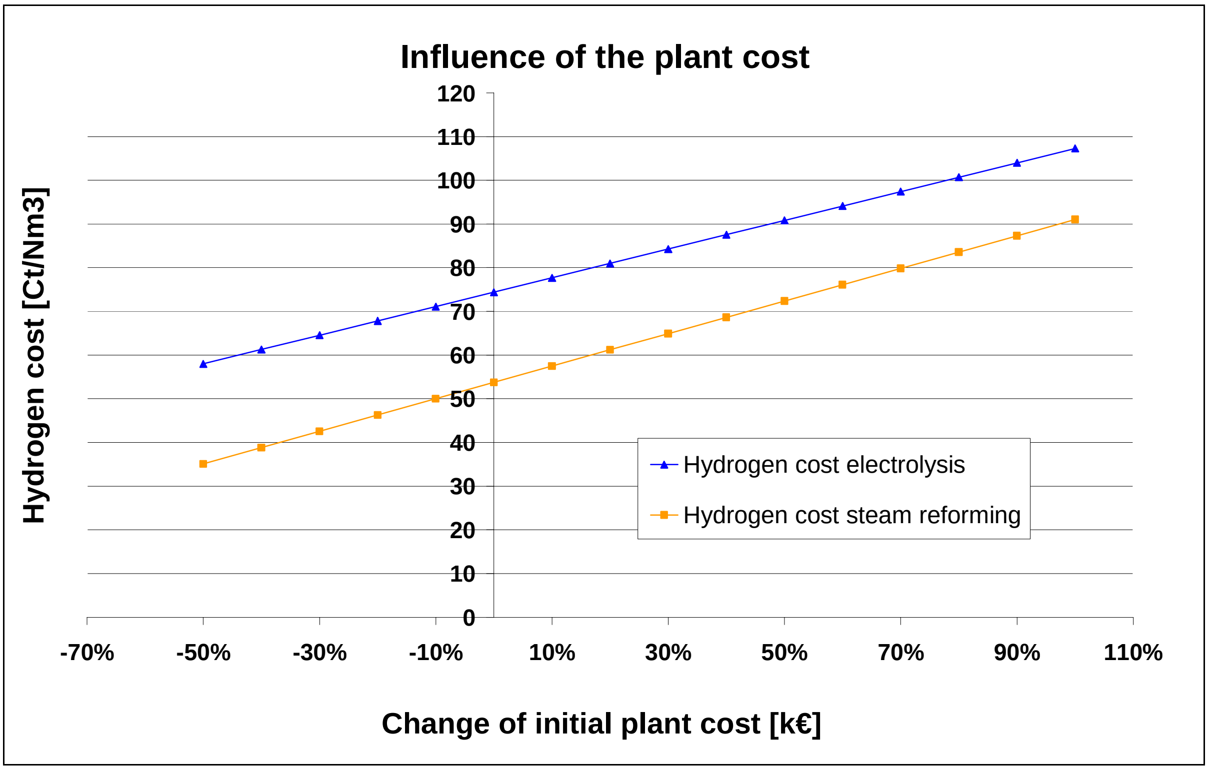

Figure 7: H2 production cost dependence on initial plant cost

6 Summary

Several cost prediction methods for the main cost drivers have been presented. The up-scaling formula, which is based on the six-tenths factor rule, the experience curve effect and the annuity method have been integrated into a cost prediction model for producing H_2 for public transportation at on-site steam reformer and electrolyser plants. Parameters were determined from literature sources to develop the different scenarios.

The results have been illustrated and analyzed and the influence of the plant cost and the feed costs have been determined. It was shown that both the plant cost and the feed cost are very important to predict the hydrogen production cost.

7 Outlook

The results of this work are based on literature sources. In the scope of the EU project “Clean Urban Transport for Europe (CUTE)” the model will be adjusted to values determined during the project. Concerning the hydrogen production and distribution in general the following conclusions were drawn.

Hydrogen is not easy to store because of its very low density and high diffusivity. Therefore transportation of hydrogen is rather difficult. To increase the amount of the transported H_2 for long distances a liquefaction is the most economic way, short distances are covered with pressurized hydrogen. However, liquefaction is energy-intensive leading to a decreased overall efficiency. Transport of pressurized hydrogen requires heavy steel cylinders which leads to the fact that most of the energy necessary for transportation is needed to carry around the steel tanks while the stored hydrogen inside is rather light (300-600 kg per trailer compared to around 5000 kg per trailer when liquefied).

A possible solution is to generate the hydrogen where it is needed and use infrastructure being already available such as the power grid or the pipeline system for natural gas. For locally produced hydrogen the lower efficiency of small plants (mainly concerning the steam reformer) and the fluctuations in demand (which have to be counteracted by a lower average utilization rate and/or bigger storage facilities) are a disadvantage.

For the electrolysis the difference between the efficiencies of small plants and big plants is minor because of the modular construction. Efficiency effects based on the plant size just can arise from parts as the compressor, the purification unit or the transformer.

Generally it is more economic to produce hydrogen directly from fossil fuels, especially from natural gas, than converting the fossil fuels to electricity first and subsequently to hydrogen by a electrolysis process. Consequently, as long as fossil fuels are used to produce electricity it is rather reasonable to take these fuels and convert them directly into hydrogen than taking a detour over the electricity grid which would be inefficient.

Electrolysis will be important to store electricity that cannot be consumed at the time it is produced (e.g. peaks of wind and photovoltaic energy) and maybe in areas where no fossil fuels are consumed and there is still a surplus of electric power.

8 Acknowledgements

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Additional thanks are going to the various industry experts which have always been helpful and were a much appreciated source of information. Their commitment was essential for the compilation of this model.

9 References

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