PHOTOVOLTAICS IN CLIMATE POLICY

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Introduction

The Kyoto Protocol will enter into force in February 2005 but the *International Energy Outlook 2004* – one of the most respected international sources with respect to energy issues – concludes that '*…based on expectations of regional economic growth and dependence of fossil energy, global carbon dioxide emissions are expected to grow more rapidly over the projection period [up to 2025] than they did during the 1990s* (EIA, 2004).' The international community still faces an enormous climate challenge and new technologies are essential in every possible long-term strategy.

Supporting the use and development of photovoltaics as a technological strategy in climate policy requires however a comprehensive argumentation. Critics will emphasize the current cost disadvantage of photovoltaics and the growing – but still modest- role wind power is assuming in several European countries. Furthermore, it is frequently stated that there exists more cost-effective strategies and technologies to reduce greenhouse gas emissions.

We partly share these criticisms[1] but think that climate policy strategies essentially consist of several complementary strategies. The growing capacity of wind energy is a very desirable development but it is not an argument *against* photovoltaics. There is a limit on the *profitable* expansion of wind power, and at that point another sustainable technology will have to take over to keep the decarbonisation process going on. Buying hot air from Russia – assuming that this option will be available at favourable conditions for countries like Belgium- is projected to be a cheap climate policy option. But after 2012, there is no hot air anymore and our growing energy use needs to be converted in a more sustainable energy use. We should therefore carefully distinguish between short-term climate policy opportunities and long-term necessities.

When comparing energy technologies, most analysts focus on cost figures. But important choices that can impact our future development should never be based on one single criterion. With a broader analysis, photovoltaics can emerge as an attractive option for several reasons. In this document, these reasons will be discussed in detail. Of course, cost information and projections of cost developments are

[1] Most analyses of cost-effectiveness in climate policy include measures to reduce emissions in a relatively short period, e.g. up to 2012, while the real potential of radically new technologies will fully materialize over much longer periods of analysis.

essential and will not be omitted. Of equal importance are the industrial opportunities associated with technology policy. The promotion of solar energy will create new activities, new jobs, new knowledge dynamics, etc. The chance that Belgium will capture economic benefits from a pro-photovoltaics strategy also depends on the current world markets for modules and systems. An overview of the current market situation is therefore included in our overview.

Finally, policymakers will decide upon the (near) future of photovoltaics. What are the policy options available and which interactions are essential to support the commercialisation and further development of photovoltaics?

<u>The structure this document;</u>

A. The relevance of photovoltaics as a policy option

B. The current market situation

C. Policy design and argumentation

D. Conclusions

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A. The relevance of photovoltaics as a policy option

By the use of semiconductor materials, photovoltaic (PV) cells convert sunlight into electricity. The seed technologies of solar photovoltaics emerged in the 1940s and 1950s but until the late 1970s, energy analysts found that PV systems could not produce energy net of the energy embodied in their manufacturing (Georgescu-Roegen, 1979). Since then, a spectacular technological evolution transformed PVs into net energy producing technologies with energy payback times of 5 to 7 years (Oliver and Jackson, 2000). In addition to the net energy production, solar technology has clear environmental benefits with the avoidance of greenhouse gas (GHG) emissions and conventional air pollutants (like SO_2, CO, NO_X and PM_{10}). PV furthermore offer the potential for a more balanced diversification of energy structures and systems that are currently overwhelmingly dependent on fossil fuels. Two decades of experiences with PV is a short period in our history of energy technology but the prospects for an solar transition improved strongly.

Despite the recent awareness of the potential role for PV, most energy market analysts seem to hesitate about the future role of solar technology in the global economy. This can be attributed to a very narrow comparison of electricity production costs in an energy *status quo* model. In its recent *World energy, technology and climate policy outlook 2030* (WETO), the European Commission (2003a) concludes that in the reference scenario PV will remain uncompetitive by 2030, a conclusion that leaves the technology only a symbolic contribution in climate policy. The relevance of this type of assessment is limited since Rich *et al*. concluded already in 1983 that the solar energy transition will have little to do with the energy *status quo* but everything with policy choices based on environmental and other considerations.

What is the future role of PVs? Obviously, there is not one unique answer to this question. In the next overview, we present several approaches to answer this question; private cost comparisons, learning curve analysis, social cost analysis and finally PV and CAPM.

1. <u>Private cost comparisons</u>

The main contributor to the cost of photovoltaic electricity is the capital cost of the system. This capital cost depends on the peak watts delivered by the system. Watt peak (Wp) indicates the peak output when solar radiation equals 1 kW per m^2 and hence determines the area of solar cells that must be purchased. The are different methodologies to calculate the electricity costs of PV but the outcomes are generally consistent.

Deutch and Lester (2004) present a cost analysis that is based on the approach of an early report of the American Physical Society. In their analysis, the capital cost per peak kilowatt, CI (\$/kWp), is expressed as the sum of the power conditioning cost to convert DC power from the PV modules into AC power for the utility, the cost of the photovoltaic array – comprising many individual photovoltaic modules- and the associated land cost. The costs are then calculated:

$$CI\ (\$/kWp) = f[C_p + (C_S + C_a)/\eta q_p]$$

with :

f = indirect cost factor, roughly 1.35

C_p = power conditioning cost, about \$140/kWp

C_S = site cost, about \$20/m^2

C_a = array costs in \$/m^2

q_p = peak solar insolation (kWp/m^2)

η = array efficiency

With a capacity factor of 25%, a ten-year loan with a 10% constant interest payment per year, a typical cell efficiency of 10% and a peak solar flux of 1 kWp/m^2 and finally zero array costs Deutch and Lester (2004) conclude that the electricity cost from PV would be 3.4 US\$cents per kWh. The calculation excludes maintenance and backup power costs. Of course, array costs are never zero so this estimates is rather a lowest possible price limit. Today, photovoltaic cells in encapsulated arrays can be manufactured for between \$1 and \$2 per peak Watt. The following table illustrates how the electricity cost varies with the array cost:

Array capital cost ($/Wp)	Array cost (cents/kWh)	PV system cost cents/kWh)
0.50	5.00	9.9
1.00	10.00	14.9
2.00	20.00	24.9

Starting from these cost figures, PV costs can be projected as is shown in Table I.

Table I – Estimated PV electricity costs

	1991	1995	2000	2010-2030
Delivered electricity price (cents/kWh)	40-75	25-50	12-20	<6
Module efficiency (%)	5-14	7-17	10-20	15-25
System cost ($/Wp)	10-20	7-15	3-7	1-1.5
System lifetime (years)	5-10	10-20	>20	>30
US sales (MW)	75	175	400-600	>10 000

Source: Deutch and Lester (2004), p.43

Deutch and Lester (2004) conclude that although the price of photovoltaics has been falling, there is still a long way to go. Furthermore, the system lifetime target have also not been demonstrated what leads to rather optimistic projected economic costs. But their analysis equally shows that there are different technological fields that can innovate to lower the electricity cost from PV.

With an alternative cost calculation that leads to rather similar results, Van der Zwaan and Rabl (2003) present the cost of PV in terms of capacity costs ($/Wp) and electricity production costs (cent/kWh). The cost of PV consists of solar module costs and associated BOS (balance of system) costs. Given the diverse applications of the solar modules and the very different BOS requirements, it is preferable to report cost ranges. For single and multi-crystalline silicon, the capacity cost of grid-connected PV systems is 3-8 $/Wp. For amorphous silicon and other thin film these costs are 2-7 $/Wp. For a stand-alone PV system, the capacity costs are much higher and lie in the range of 4-30 $/Wp.

Van der Zwaan and Rabl (2003) calculate the cost per kWh of PV by adding[2] operation and maintenance as well as financial costs to the capacity costs ($/Wp). Based on an economic lifetime of 25 years, a real interest rate of 5%, annual operation and maintenance costs at 2% of the capacity cost and a realistic degree of climate

[2] C ($ cent/kWh) = C_{cap} [$C_{o\&m}$ + $r/(1-(1+r)^{-N})$], where C_{cap} is the capacity cost, N the economic lifetime of the system, r the real interest rate and $C_{o\&m}$ the annual cost of operation and maintenance as percentage of C_{cap}

variability, they find that the electricity costs for grid-connected PV range between 13.6 and 18.2 cUS$/kWh for single crystalline silicon and multi-crystalline (or polycrystalline) silicon, and between 9.1 and 12.1 cUS$/kWh for amorphous silicon and other thin film. Currently, the share of single crystalline silicon and multi-crystalline silicon amounts to 89% of total module production (Maycock, 2004) implying that the 'average' PV electricity cost is closer to 15 cents that to 10 cents per kWh[3]. Most authors compare these costs to a production cost of 4 cents/kWh for base load electricity from an efficient fossil-based plant. For stand-alone PV technologies, the electricity costs are much higher (+70 to +100%).

These figures illustrate the current cost-disadvantage or cost gap for PV. From a dynamic perspective, the evolution of this gap is of equal importance. This kind of forward looking cost analysis is frequently based on learning curve analysis.

2. Learning curve analysis (experience curves – progress ratio)

Experience curves describe how unit costs c (here US$ or €/Wp) decrease with cumulative production, S(Wp),

$$c = c_0 \, (S/S_0)^{\beta} \tag{1}$$

$$\text{or: } S = S_0 \, (c/c_0)^{1/\beta} \tag{2}$$

Where c_0 is the initial unit cost and S_0 the initial cumulative production at time $t_0=0$. The experience index is

$$\beta = \frac{\ln r_p}{\ln 2} \tag{3}$$

where r_P is the so called progress ratio. A progress ratio of 0.80 means that the costs decrease by 20% for each doubling of cumulative production. In this example the experience index is -0.322. Literature overviews on PV modules suggest historical progress ratios of 0.77 – 0.82 and hence learning effects or learning rates of 0.18 –

[3] It is furthermore expected that especially multi-crystalline silicon will continue to dominate the PV market in the coming years.

0.23 (Parente *et al.*, 2002). Of course, these parameters are based on historical information and implicitly assume that the underlying production is rather homogeneous.

Sanden (2004) uses equation (2) to calculate the amount of PV systems that need to be produced to reach a target price that is competitive to coal-based electricity. For this exercise, the following assumptions are used: a progress ratio of 0.8 for PV systems, a cumulative production S_0 in 2000 of 1.46 GWp, a unit cost c_0 in 2000 of 6 US$/Wp and a target cost c_1 of 1 US$/Wp. Depending on solar irradiation, this target cost roughly corresponds to 4-8 cUS$/kWh. Sanden (2004) finds that the total cumulative production to reach the target cost is 382 GWp. With an annual growth rate of cumulative production of 30%, the target cumulative production can be reached after 21 years. With a slower growth of 15% per year, it would take 41 years to reach competitiveness. These findings should be compared to the historical annual growth rate of 24% of the PV market since 1976. Between 1998 and 2002, the annual growth rate of the PV market increased to 32% (Poponi, 2003). These results require us to consider the validity of such extrapolations. Martin Green (2003) presented at the *2003 World Conference on Photovoltaic Energy Conversion* PV learning rates or progress ratios compared to the past experiences with gas turbines and wind generators. He concluded that for gas turbines and wind generators, the learning rates switched from the same 20% now observed for PV to much lower rates around 5 to 10%, and finally towards a more or less stabilized prices. For gas turbines, the first reduction of the learning rates took place around 1963 while for wind turbines 1993 was the last year with a 20% learning rate. If this progress pattern will materialize for PV, cost competitiveness will not be reached within 20 years.

In a next step, Sanden (2004) calculates the subsidy cost to support the global PV production project – based on the difference between the electricity cost from PV and the target cost- and expresses this subsidy cost in relation to the annual electricity production in OECD countries. With a progress ratio of 0.80, the subsidy cost would peak at 0.1 cUS$ per kWh. When this relative subsidy cost is compared to the cost of the German coal subsidies – estimated around 1 cUS$ per kWh- Sanden concludes that PV could be a low cost strategy to radically change the current electricity system. Presenting the subsidy cost as relative to actual electricity consumption is however of limited relevance. The crucial question is who is going to pay the subsidy cost to let PV production grow to 382 GWp. When all OECD countries charge an additional tax on their electricity use to finance these subsidies, the presentation by Sanden makes sense. But only a limited number of OECD countries have currently an active policy to support PV. Why then should countries that not even consider PV as a viable climate policy strategy finance such an ambitious subsidy program? The comparison to German coal subsidies is illustrative in this context. Germany finances these subsidies because of strong internal powers that can influence the policy process. But where are the strong powers inside the OECD that will fight for the imposition of a global pro-PV electricity tax? Of course, supporting the take-off of PV should not solely be based on electricity taxes. Whatever instrument or approach is selected, only a strong and growing coalition of countries that commit themselves to PV can succeed. Given the limited number of countries that actually invest in PV, a sudden policy change in a country like Germany can endanger the growth rate of the global PV market.

Results from learning curves analysis should be carefully interpreted by national policymakers. No single agent is managing the global market, nor global production (in cumulative MW). This implies that national policymakers can not influence the evolution of the progress ratio. Furthermore, the progress ratio is the result of joint actions by an unknown number of participants. The unit cost impact of efforts by companies in country *X* depends on the efforts by companies in the other n-1 countries (with n as a variable, not as a constant). At the level of the individual company, a lower unit cost for PV modules that will be produced in the future can only be the result of targeted efforts and investments to improve process efficiency. As a result, only companies that can invest in future expansions of production and have access to updated process innovation information, will benefit most of potential learning effects. The ability to invest depends on attractive market prospects and access to financial markets while access to relevant knowledge is the result of past interactions with other firms (competitors as well as suppliers and customers), universities, research organisations, independent scientists, etc. The latter condition suggests that experienced firms that operate inside a broad network have the highest chances to benefit from the progress ratio inside an industry.

3. Social cost analysis

Learning curve analysis as presented in the former paragraph is limited to private production costs. Especially for policymakers, other than private production costs should also be considered when comparing different technologies.

The environmental benefits of PV provide the most important justification for public investments in this technological trajectory. The calculated cost gap of some 5-15 cUS$/kWh for grid-connected amorphous silicon and respectively multi-crystalline PV neglects the environmental costs associated with electricity based on fossil fuel power plants. When we calculate the external costs for fossil-based electricity and add these to the private production cost, we obtain the social cost in cents per kWh electricity produced. Obviously, the social cost of fossil-based electricity exceeds the often referred to private cost benchmark of 4 cUS$/kWh. A precise calculation of external costs is very problematic[4] but research during the last decades made it possible to estimate ranges of external costs for specific pollutants emitted by power plants (EC, 2003b).

Van der Zwaan and Rabl (2003) present some damage costs based on fuel chains in the EU. The most important conclusion of this type of analysis is the strong projected reduction of non-climate external costs – other than the external costs from CO_2- with the newest types of gas, coal and oil plants. While the non-climate damage cost (PM_{10}, SO_2 and NO_X) of a coal-fired plant built in the 1990s was calculated at more than 10 cents/kWh, the damage cost for the most recent plants slightly exceeds 1 cent/kWh. The non-climate damage cost of the most recent gas and oil plants is 0.2 respectively 1.3 cents per kWh. The calculation of the climate cost of pollutants like CO_2 and CH_4 is very problematic since these costs did not yet materialise, at least not at a distinguishable scale. These damage costs therefore need to be based on discounted future damage costs but it is currently highly uncertain where the local impacts of a global warming will be most visible. As an alternative for these methodological problems, avoidance costs are frequently used (EC, 2003b). Avoidance costs are shadow prices to reach a specific environmental target, e.g. the reduction targets of the Kyoto Protocol. But then we end up with the problematic situation in which countries with a soft Kyoto target have a lower CO_2-damage cost

[4] External costs are by definition location specific because exposure depends on geographical characteristics such as population density.

than countries with an ambitious Kyoto target. We can however mention that for most countries, a climate change damage cost around 2 cents per kWh is frequently used for coal-fired power plants (EC, 2003b).

Without climate costs, the inclusion of damage costs of the most recent fossil fuel electricity plants into the price would reduce the cost gap with PV to 3.5 to 13.5 cents/kWh. When a climate cost of 2 cents is added, the price gap is further reduced to 1.5 to 11 cents per kWh. When the oldest coal-fired plants are considered, PV would have a cost advantage but this would only be temporary since the oldest plants will not be operational within 20 years. So without climate costs, prices based on social costs will not close the cost gap for PV. This finding is not undermining the viability of PV since climate policy is not based on precise calculations of future damages but on approaches and strategies to meet short- and middle-term reduction targets. So although policymakers do not know the damage cost per ton CO_2 emitted, they can gradually introduce a price penalty on GHG emissions to reduce total national emissions.

4. PV and CAPM

The potential of PV is mostly assessed by engineering concepts such as learning curve analysis. In financial valuation, portfolio theory or the Capital Asset Pricing Model (CAPM) is widespread used for comparative valuation exercises. The key feature of CAPM is a risk-adjusted valuation of assets/resources that compose a portfolio (see Varian (1993)). With CAPM, the true relative value of PV can only be determined by evaluating alternative energy technology portfolios. This analysis can yield different outcomes than simply comparing alternative energy technologies without considering the total energy system. In conventional cost comparisons of alternative energy technologies, important risk categories that are typical for the whole portfolio are often neglected what limits the relevance of the results[5]. This section will illustrate the valuation of PV based on CAPM.

[5] In private investment analysis, the 'risk-aware' CAPM-investor first considers the content of its portfolio (e.g. 60% stocks, 40 % bonds) then the sectoral characteristics of the selected assets (e.g. 20% ICT, 25% distribution) and finally his attention is focused on the performance of individual companies. A less risk-averse investor would simply buy a number of stocks that seem to outperform the market.

4.1 CAPM and energy system risks

To elaborate the use of CAPM, we need to acknowledge that the cost disadvantage of PV - 3.5 to 13.5 cents/kWh based on non-climate damages- neglects two crucial questions:

a. can we assume that the production cost of 4 cents/kWh for base load electricity from an efficient fossil-based plant remains constant over time, and:
b. how should our future energy and electricity infrastructure look like?

With record prices for fossil fuels – up to 55,67 $ per barrel in October 2004 and the ongoing tensions on world oil markets-, many of the long-term oil price projections are revised (or revision is considered). Gas prices also strongly increased but this market is characterised by regional differences. In the WETO 2030 report of the European Commission (2003a), the oil price for all the reference scenarios is projected to reach 35 €/bl in 2030[6]. A sudden price jump is not a reason to revise long-term projections but there are clear indications that current price rises are al least partly structural. The demand-impact of ongoing strong economic growth in China, India and Russia[7]**,** seems to be underestimated by most international economic organisations. Given the dependence of our individual transport systems on oil and to a lesser extent on natural gas, the opportunity cost of burning oil for electricity generation will increase. If electricity producers then opt for the lowest cost alternative, (clean) coal-fired plants can become attractive again. Currently, the US Department of Energy already funds 65 carbon sequestration research projects for $110 million under its clean coal program. As part of its climate policy strategy, the US also invested in clean coal collaboration agreements between China and India (US Department of Energy, 2003). Carbon sequestration will lower CO_2 emissions into the air but will definitely increase the cost of coal-fired plants because of the efficiency losses from sequestration[8]. More coal-fired electricity plants will bring a new challenge for air quality policy in most developed countries, eventually leading to higher average production costs because of rising SO_2 and NO_X abatement costs.

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[6] The WETO 2030 report was written at a time when 1 € was priced less than 1 US$.
[7] Real growth of GDP in China, India and Russia was respectively 8% (2002), 8% (2003) and 7.3% (2003).

Probably everyone realises that out energy and electricity infrastructure in 2040 or 2050 should not look like the current fossil-based model. Developed countries cannot escape their responsibility with respect to the climate challenge and the pollution from current electricity production should be further reduced. Of equal importance, the technologies to reduce GHG as well as non-GHG pollution should be transferred to the new centre of the global economy in 2050 – Asia – and other regions. The richest countries face a transition to a low-carbon and low-pollution economy. In countries like the UK, this challenge is now an explicit part of long-term economic policy. In 2003, the UK Department of Trade and Industry (DTI) published its energy white paper that aims at a 60% reduction of greenhouse gases – compared to 1990 levels- by the year 2050 (DTI, 2003). This document is supported by the British government as well as British industrial federations. With this explicit goal, the UK wants to become the leading European low-carbon economy and gain a long-term comparative advantage from the new energy technologies that are needed to realize the reduction target. Apparently, the future market prospects of renewable and low-carbon energy technologies are too attractive to allow countries like Germany, Denmark and Spain to further strengthen their EU leadership.

Given the gravitational powers of the current *Techno-Institutional Complex* with its carbon lock-in (Unruh, 2000), policymakers will prefer smooth transitions that respect existing economic interests of the dominant players. New technologies that gradually complement existing technologies provide the key solution because they do not endanger vested interests. Once new technologies are ready for commercialisation, dominant players can diversify their portfolios by investing in the new technologies. This is what is currently happening with wind energy in several European countries.

In addition to environmental concerns, energy security returned back as an international issue since the terrorist attacks on September 11, 2001. All developing countries are aware of the need to diversify their energy supply and hence electricity production. And with the record high oil prices and the recent revisions of known oil reserves by several major oil companies, fears for an energy scarcity are expressed in popular media.

The conclusion of this overview of environmental concerns and energy-related risks is that energy planners should carefully balance *least-cost* alternatives versus *least-risk*

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[8] The efficiency losses are estimated between 10 to 15%.

alternatives. Therefore, from a national policy perspective, incorporating riskless physical assets such as PV and wind may be essential for long-term energy security and reliability (Awerbuch, 2000a). Renewables are termed *riskless* for two reasons: they face no price volatility with respect to inputs during use[9] of the installation and neither the risk for future environmental restrictions on the use of the technology. Given the further depletion of fossil fuel reserves and the accumulation of environmental stresses – reflected by the continuously increasing atmospheric concentration of CO_2- our current carbon lock-in will gradually evolve into a too risky economic and social infrastructure. This is a certainty, not an assumption. The remaining uncertainties are related to the length of the available transition period. Can we afford to proceed with business-as-usual until 2015, 2025 or 2035? A political answer to this question will be based on the ability to reduce the expected risks and the economic consequences of the risk-reducing strategies.

4.2. CAPM and price volatility risk

Properly designed portfolios yield a portfolio effect, i.e. a reduction of portfolio risk through diversification. Investors base their ultimate investment decisions on the trade-off between portfolio return and portfolio risk. Only high returns can motivate the acceptance of high risks and vice versa. In the context of electricity generating technologies, our portfolio is composed of physical assets that produce an output in kWh. Returns on a technology can be compared when expressed as dollarcent per kWh produced or as kWh per dollarcent. The latter option yields a graphical presentation of outcomes that is very similar to the results from conventional financial portfolio analysis, and is also used by Awerbuch (2000b) and Awerbuch and Berger (2003). The price volatility risk of a generating technology is simply the standard deviation (SD) of fuel prices, computed for the period 1990-2002. Data from IEA (2003) were used for coal and gas prices. Given the significant national differences for coal and gas prices in the EU, we used as price for coal for electricity generation the average coal price in Belgium, Finland, France and Germany. The natural gas price for electricity is calculated as the average price in Finland, Germany, Hungary

[9] With respect to the production of PV modules, manufacturers face price volatility risks for the used materials (semiconductors). Most authors do not foreseen semiconductor scarcity problems.

and Ireland. Uranium prices (U_x U_3O_8) from The Ux Consulting Company[10] were used. The calculated standard deviations of the gas, coal and uranium prices are respectively 0.109, 0.244 and 0.173. The correlation coefficients between gas and coal, gas and uranium and coal and uranium are respectively –0.226, 0.354 and –0.0157.

4.2.1 CAPM 2005

We illustrate the insights from portfolio theory with an analysis of five generating technologies for the EU in 2005; gas fired (CCGT), coal fired (steam boiler), nuclear, wind and PV. We then present two scenarios for 2025. Oil-fired plants are not considered, mainly because of the modest prospects for oil-fired plants in the EU.

Table II – Technology returns in three scenarios

Technology	KWh/cent in 2005	KWh/cent in 2025 (A)	KWh/cent in 2025 (B)
Gas	0.40	0.45	0.36
Coal	0.32	0.34	0.25
Nuclear	0.29	0.30	0.30
Wind	0.27	0.36	0.36
PV	0.12	0.30	0.30

Given the significant differences in fuel prices, used technologies and average age of technologies in portfolios in EU-countries, every assessment of average returns on power plants in the EU hides many differences. However, the values presented in the second column of Table II for the year 2005 are closely in line with the existing literature. The returns for 2025 (two scenarios: 2025 A and 2025 B) will be explained later.

In a first step, we calculate the returns and risks of all portfolios in 2005 that only make use of gas, coal and nuclear technology. The portfolio return is simply the weighted sum of the technology returns. For 2005, the highest (theoretical) portfolio return is hence 0.4 (with only gas technology used). The lowest return for 2005 would be 0.27 when only nuclear capacity is used for electricity generation.

Portfolio risk is a weighted average of technology risks (SD of input prices) tempered by the correlation coefficients[11] between all technologies.

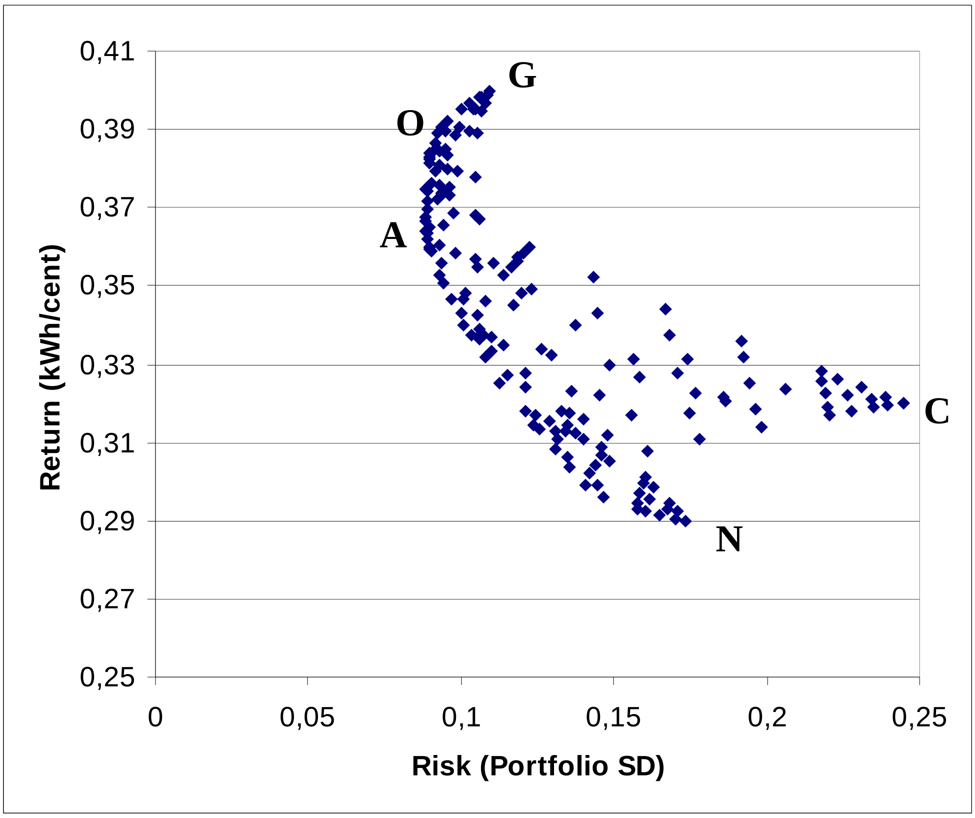
[10] http://www.uxc.com/review/uxc_prices.html
[11] This effect is of special relevance with negative correlation coefficients.

The variance[12] of a portfolio with N technologies, with X_i as the share of technology i in portfolio, σ_i as fuel risk for technology i (SD of fuel prices) and ρ_{ij} as correlation coefficient between the returns[13] is:

$$\sigma_p^2 = \sum_{i=1}^{N}\sum_{j=1}^{N} X_1 X_2 \rho_{ij}\sigma_i\sigma_j$$

Figure I presents the results for portfolios that only include gas, coal and nuclear technologies. G stands for a 100% gas portfolio, C for a 100% coal portfolio and N for a 100% nuclear portfolio. All the other points in figure I represent a combination of more than one energy technology.

Figure I – Portfolio analysis for gas, coal and nuclear technologies



[12] The standard deviation is the square root of variance.

The combination of gas, coal and nuclear technology in point A delivers the lowest portfolio risk (SD= 0.088). Figure I shows that there are several combinations of energy technologies that deliver a comparably low risk level at different portfolio returns. Table III presents portfolio results for several ‘low risk’ combinations close to point A in Figure I.

Table III. Returns and risks of portfolios close to A

Return (kWh/cent)	Risk (SD)	Share of gas	Share of coal	Share of nuclear
0.382	0.0897	78%	22%	-
0.374	0.0887	70%	24%	6%
0.371	0.0890	70%	15%	15%
0.369	0.0887	68%	16%	16%
0.367	0.0886	66%	17%	17%
0.366	0.0882	64%	20%	16%
0.365	0.0894	64%	16%	20%

The portfolio analysis clearly presents the risk-return trade-off with the selection of energy technologies. All the combinations between A and G in Figure I are considered to be on the efficiency frontier since moving from A to G results in higher returns at a higher risk. Moving from A to N or from A to C would result in lower returns at a higher portfolio risk, clearly an unattractive option. Ultimately, the selection of a technologies between A and G depends on the risk averseness of energy planners.

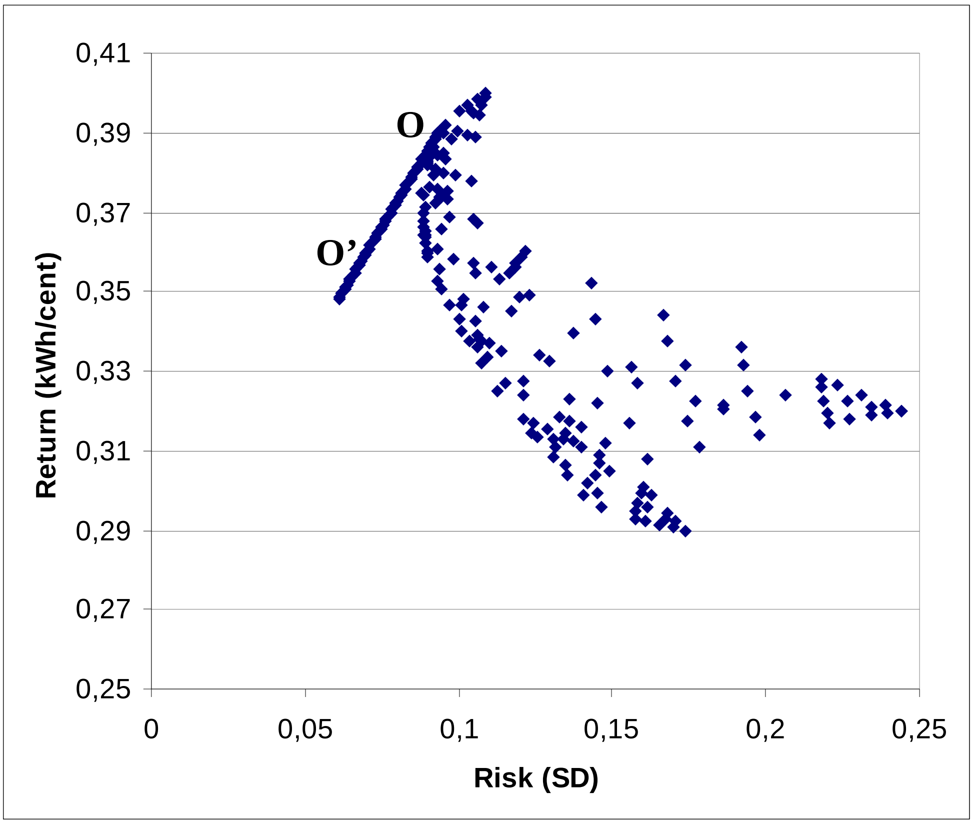
Without renewable energy, policymakers can not reduce total portfolio risk below SD=0.0886 and are limited to efficient choices between A and G. The inclusion of renewable energy in the analysis for 2005 reveals the unique role of renewable energy. In this analysis, renewable energy offers a risk-less alternative since there are no input prices. A hypothetical portfolio with only wind energy would deliver a return of 0.27 (see Table II) at no risk. Hence the correlation with other input prices is zero. Figure II shows the portfolio consequences of adding wind technology to any of the efficient combinations between A and G. Starting from combination O (88% gas and 12% coal), a linear increase of the share of wind from 0 to 35%[14] of the total

[13] Since in this simplified analysis, only the fuel risk is considered, any change of the return in kWh/cent is due to input price fluctuations. Hence, the correlation coefficient between returns is equal to the correlation coefficient between input price series.

[14] A 35% share of renewable energy is currently problematic in terms of grid management and grid reliability. Electricity generation from intermittent renewables can range between 10 and 30% of total generation without any side effects on system reliability if the backup generation is provided mainly by hydro or gas-fired plants which have quicker load-change following capacity (Poponi, 2003).

portfolio results in the straight line OO'. The shares of gas and coal in the new portfolio are both reduced by the percentage of wind energy. A further increase of the share of wind would result in OO' intersecting the Y-axis at a portfolio return of 0.27 kWh/cent.

Figure II - Portfolio analysis for gas, coal, nuclear and wind technologies

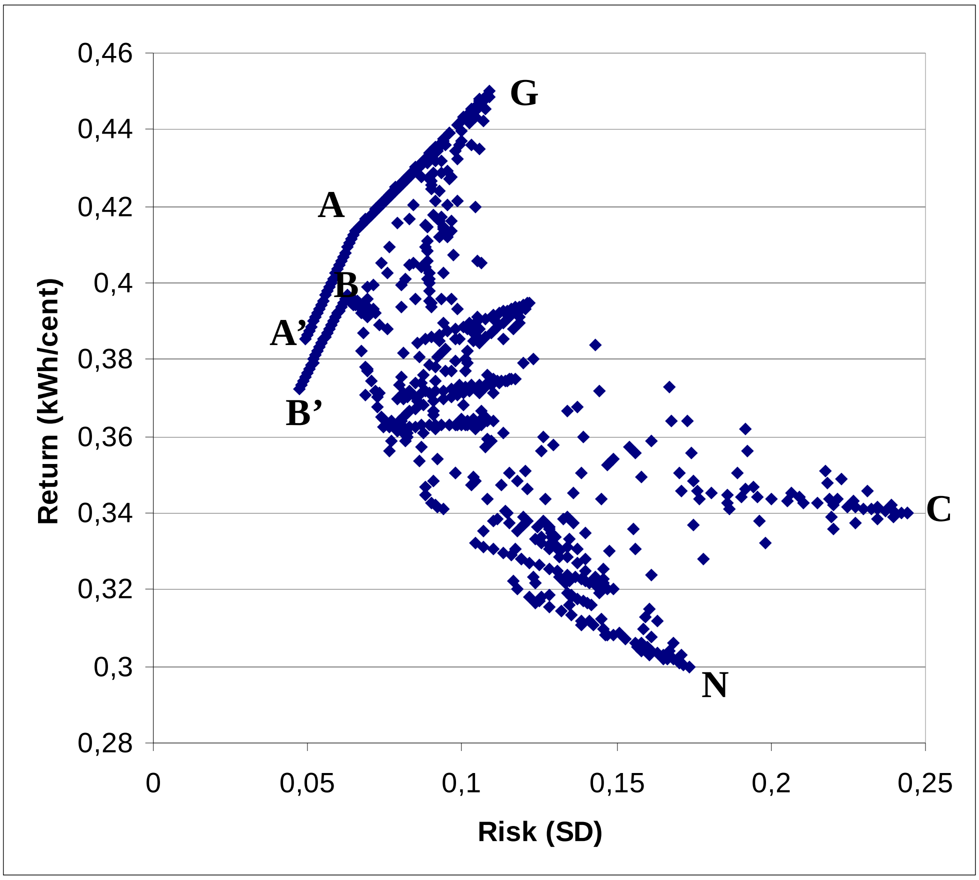


The inclusion of wind energy strongly expands the number of efficient combinations from A-G to O'-G. Of equal importance is the unique ability of renewable energy to reduce portfolio risk. A 20% share of wind energy – in a portfolio with 70.4% gas and 9.6% coal- results in portfolio risk of SD=0.0562 and portfolio return of 0.3663 kWh/cent. Compared to Table III, an almost equal portfolio return is realised at a much lower portfolio risk. The inclusion of wind energy eliminates the formerly efficient combinations between A and O (see Figure I) since these result in portfolio returns at much higher risks than necessary.

4.2.2. CAPM 2025 A

Based on the parameter values in Table II, the simulation for 2005 is repeated for 2025. We assume that in 2025, PV is as competitive as nuclear energy (0.3 kWh/cent) but still uncompetitive when compared to the other energy technologies that could all improve their efficiency. This scenario appears optimistic but is in fact still biased against renewable energy for two reasons. Firstly, we assumed that input prices (natural gas, coal and uranium) are identical to those in 2005, and that the price volatility of these input prices up to 2025 is also identical to the price volatility used in the simulation for 2005. More price shocks such as in October 2004, will increase price volatility of fossil fuels. This will of course increase the portfolio attractiveness of renewable energy. The impact of higher prices can also be limited because of further technological improvements that make it possible to produce more electricity from the same inputs. As a benchmark, it is however very informative to analyse the contribution of PV under the biased simulation. The results are presented in Figure III. We consider first the situation without PV. Figure III is more complex because of the additional technology –wind technology- in the portfolio. From several combinations of technologies, more or less straight lines depart. This pattern is caused by the linear increase of wind energy to a combination that initially excluded wind energy. The extrapolation of these lines would result in intersecting the Y-axis in a return of 0.36 kWh/cent, i.e. the return of wind energy in 2025. Without PV, the efficiency frontier is the line form A to G. Portfolio A (61.6% gas, 8.4% coal and 30% wind) yields a return of 0.4137 and a portfolio risk of 0.0656. Combination B (50% gas, 9.5% coal, 10.5 nuclear and 30% wind) is another efficient combination resulting in a return of 0.3968 and a portfolio risk of 0.0628. Policymakers can jump from B to A to increase portfolio return at the cost of a higher portfolio risk and can then move from A to G, what will confront them to the classical trade-off of higher returns against higher risks. The inclusion of PV strongly expands the efficiency frontier in the CAPM 2025 A simulation. We add PV to the combinations A and B to obtain respectively the new efficiency frontier from A' to G and a less interesting set of combinations from B' to B.

Figure III – Portfolio analysis for 2025 without PV



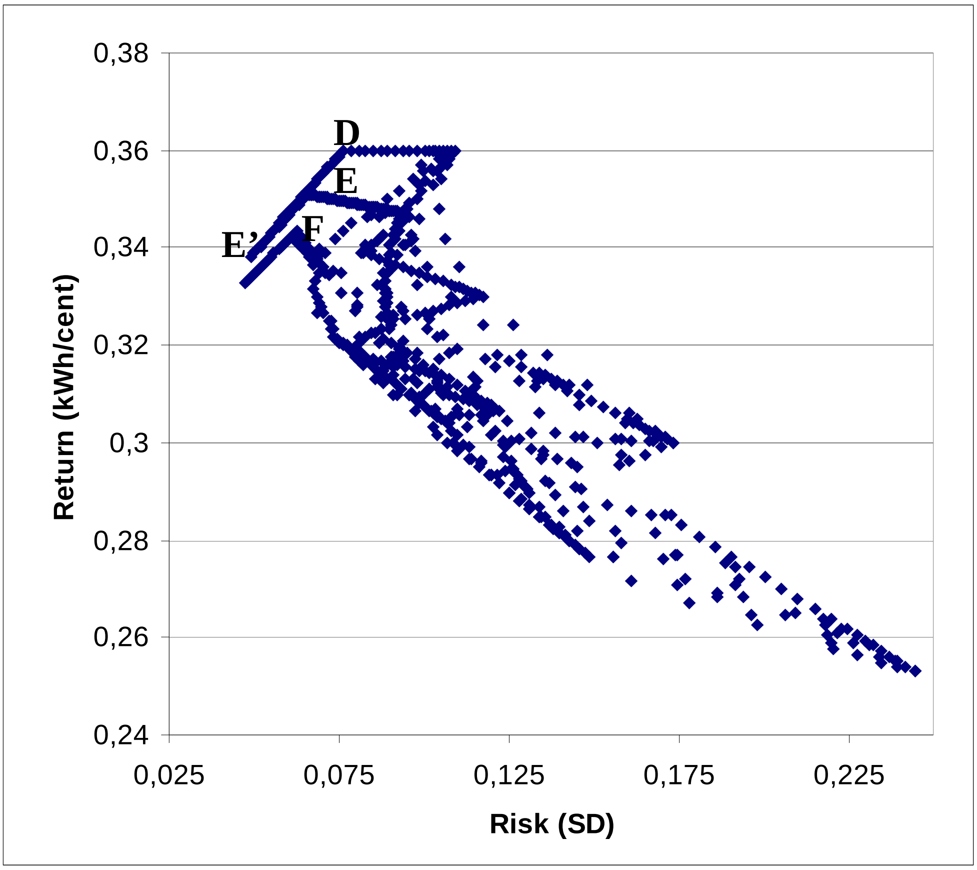
In the simulation, the share of PV is gradually increased up to 25% of the total generating portfolio. In B' (37.5% gas, 7.12% coal, 7.87% nuclear, 22.5% wind and 25% PV), portfolio risk is minimised at SD=0.047 with a return of 0.3726. In A' (46.2% gas, 6.3% coal, 22.5% wind and 25% PV), portfolio risk is 0.0492 and the portfolio return equals 0.3853 kWh/cent.

In combinations A' as well as B' the total share of renewable is 47.5% of all generating technologies. Although the ability to manage high share of renewables on the grid can increase, this high share is probably not realistic. A lower share of renewables – 25.5% wind, 15% PV together with 52.4% gas and 7.1% coal- results in a portfolio risk of 0.0557 and a portfolio return of 0.3966. This level of portfolio return is highly competitive when compared to portfolios with a high share of coal and/or nuclear. This analysis confirms that investing in renewable energy should be valued from a broader perspective than just comparing the cost of one technology to another.

4.2.3. CAPM 2025 B

The simulation for CAPM 2025 B differs from CAPM 2025 A because of the inclusion of environmental costs. All other assumptions for CAPM 2025 with respect to the energy input prices remain unchanged, leading to an analysis that is in fact strongly biased against renewable energy. The parameter values in Table II reflect the impact of environmental costs on technology return. Policymakers can impose environmental costs upon polluters by charging an environmental tax on every kWh produced. We assume a tax of 0.5 cent per kWh electricity produced in a gas plant and a tax of 1 cent per kWh electricity from a coal plant. The return parameters in the last column of Table II are after tax returns, based on the pre-tax returns in CAPM 2025 A (third column of Table II)[15]. The results from the CAPM 2025 B simulation are presented in Figure IV.

Figure IV – Portfolio analysis for 2025 with PV



[15] A return of 0.45 kWh/cent for gas implies a kWh production cost of 2.22 cent (1/0.45). After the tax, the production cost increases to 2.72 cent what implies a return of 0.36 kWh (1/2.72).

Although scenario 2025 B is presented as a scenario including environmental costs, higher input prices and no internalisation of external costs can provide an alternative explanation for the 2025 B parameter values in Table II. Higher input prices will reduce the production of kWh per invested cent[16].

Figure IV shows that including wind energy increases the portfolio return. The straight lines in Figure IV will intersect the Y-axis at the return of 0.36 kWh/cent. Without PV, we obtain a hypothetical efficiency frontier by connecting the points D (70% gas, 30% wind), E (61.6% gas, 8.4% coal, 30% wind) and F (50% gas, 9.5% coal, 10.5% nuclear, 30% wind). With F, the portfolio has the lowest possible risk of SD=0.0628 while the return equals 0.3435 kWh/cent. When PV enter the analysis, a new efficiency frontier from E' (46.2% gas, 6.3% coal, 22.5% wind, 25% PV) to D emerges. Portfolio risk of E is 0.0492, for a return of 0.3382. When the total share of the two renewable technologies is reduced to 40.5% of the portfolio (52.4% gas, 7.1% coal, 25.5% wind, 15% PV), a portfolio risk of 0.0557 is obtained together with a return of 0.3433 kWh/cent.

4.2.4. Adding other risk categories – broadening the model

The presented analysis is limited to fuel price risks and neglects other relevant risks. Especially with respect to new capacities to be installed by 2025 in the simulations, construction period risks could be considered. The construction period risk relates to the precise moment of the first electricity production from the new plant and the total construction cost of the plant. The total construction cost includes private investment costs in additional to social costs such as accidents during construction and environmental damages. Obviously, existing plants do not face these construction risks. Renewable energy technologies face other construction risks than gas, coal or nuclear plants. Off-shore wind projects are characterised by relatively high construction risks when compared to on-shore wind projects and PV-installations. Although data are hardly available, PV can provide the lowest construction risks[17].

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[16] The results of the presented analysis with environmental costs and stable prices will slightly differ from the results with higher prices since the latter scenario brings changes in the standard deviation of input prices.

[17] A complete analysis of construction risks should also include fatal and non-fatal accidents with roofers that install PV modules. The cost of these accidents can be seen as 'external' PV construction costs.

Awerbuch and Berger (2003) also consider operation and maintenance cost risks. When these risk categories are added, renewable technologies are no longer risk-free but bear some degree of market risk.

Both new risk categories can improve the quality of the portfolio analysis. However, relevant data are hard to find or do not exist. Awerbuch and Berger (2003) therefore complement their analysis by using financial proxies such as the historic standard deviation for various corporate bonds. The results from their more complete risk analysis however confirm the conclusions of the analysis with only fuel price risk, even when the risk parameters are changed significantly in a sensitivity analysis. This is not surprising since the fuel risk clearly dominates all the other market risks for the electricity sector.

Finally, the presented analysis is limited because of the selection of energy technologies. Other renewable energy technologies than wind and PV are not considered. In principle, there can be competition between different renewable technologies. In the appendix, we introduce biomass into the portfolio model. Our results illustrate that short-term cost-comparisons need to be clearly distinguished from long-term cost comparisons.

4.3 Conclusions

The cost disadvantage of the PV installations that currently dominate the market are still significant (between 10 and 15 cents per kWh). The electricity price from fossil-based power plants and nuclear plants however excludes historical subsidies that made these technologies competitive, as well as the social costs from the production. When social costs are added to private production costs, the cost disadvantage of PV is reduced. With the most modern types of fossil-based power plants, the remaining external costs are relatively low. Even a perfect internalisation of external costs will never make current PV technologies competitive.

The global PV market grows by some 30% each year and this evolution will generate important cost reductions in the future. Sanden (2004) calculated that PV can become competitive after some 20 years of further growth. There are however no guarantees that the progress ratios or learning ratios will remain identical over the coming decades. Green (2003) presents evidence of strong reductions in learning effects for gas and wind turbines and when the same phenomenon takes place for PV, competitiveness will be further postponed.

Cost competitiveness is however but one factor in a complex analysis. Our future energy systems need to adapt to new market realities. Reserves of fossil fuels are limited and price increase are inevitable. Sudden price shocks have significant macro-economic impacts with cost consequences that are measured as a percentage of lost GDP instead of additional cents per kWh. Strategic energy dependence is another aspect of future energy systems. All developed countries need to reduce their dependence on oil and renewable energy can contribute to this goal. Our portfolio analysis showed that PV, next to wind energy, offers the ability to reduce the risk from fossil-fuel dependence while the cost consequences of an energy system transformation are modest. Not investing in PV is much riskier than promoting the diffusion of PV.

B. The current market situation

The global photovoltaics market was and remains a booming market. Growth rates of 30% or more have become the established trend in the global photovoltaics market. 2003 was no exception, and 2004 seems to be equally buoyant. World PV cell and module production reached its highest ever level in 2003 at 744 MW (Maycock, 2004). This represented a 32.4% increase (182 MW growth in annual output) over the 2002 figure of 561.77 MW. In both Japan and Europe, production grew by over 40% - Japanese PV cell and module output increased by 45% to 363.91 MW during 2003, and there was a 43% increase in European production to 193.35 MW. However, there was for the first time a decrease in PV production in the US, which dropped by 14.6% to 103.02 MW, largely due to the collapse of AstroPower. The global PV market therefore seems to be a market in transition with opportunities for newcomers among leading companies that all are vulnerable to sudden changes in the political climate surrounding solar energy.

1. Market leaders

Table IV shows that Japan dominates the world market with a share of 48.9% in total production in 2003. Europe follows with a global share of 25.9%. The Japanese dominance is a rather recent phenomenon. In 1998, the PV market was still dominated by US firms.

Table IV. World PV production in 2003 (MWp-DC)

Region	1995	1996	1997	1998	1999	2000	2001	2002	2003
Japan	16.40	21.20	35.00	49.00	80.00	128.60	171.22	251.07	363.91
Europe	20.10	18.80	30.40	33.50	40.00	60.66	86.38	135.05	193.35
US	34.75	38.85	51.00	53.70	60.80	74.97	100.32	120.60	103.02
ROW	6.35	9.75	9.40	18.70	20.50	23.42	32.62	55.05	83.80
Total	77.60	88.60	125.80	154.90	201.30	287.65	390.54	561.77	744.08

Source: Maycock (2004)

The bulk of the PV production is highly concentrated but the market is clearly open for newcomers (see Q-Cells, Photovoltech). In 2003, the top ten manufacturers of PV cells and modules accounted for 85% (634.42 MW) of total global production (see Table V). Japanese companies maintained first and third positions, with Sharp well in the lead at 198 MW and Kyocera at 72 MW. Shell Solar came second with 73 MW, followed by BP Solar with 70.23 MW. RWE Schott jumped from seventh to fifth place, tying with Mitsubishi on 42 MW. Sanyo's production of its high-efficiency amorphous silicon/crystal silicon heterojunction product took eighth place, while AstroPower dropped out of the top ten from sixth to eleventh place at the end of 2003 (AstroPower has subsequently been bought by GE). Q-Cells, producing 28 MW in 2003, joined the top ten. Isofoton moved up to seventh place and Photowatt retained tenth position.

Table V. Top PV cell/module producers

Company	**Production by year (MW)**					**Ranking**				
	1999	**2000**	**2001**	**2002**	**2003**	**1999**	**2000**	**2001**	**2002**	**2003**
Sharp	30.00	50.40	75.02	123.07	198.00	3	1	1	1	1
Shell Solar	22.20	28.00	39.00	57.50	73.00	4	4	4	4	2
Kyocera	30.30	42.00	54.00	60.00	72.00	2	2	3	3	3
BP Solar	32.50	41.90	54.20	73.80	70.23	1	3	2	2	4
RWE Schott (was ASE)	10.00	14.00	23.00	29.50	42.00	7	7	6	7	5
Mitsubishi	N/A	12.00	14.00	24.00	42.00	N/A	9	9	9	5
Isofoton	6.10	9.50	18.02	27.35	35.20	-	10	8	8	7
Sanyo	13.00	17.00	19.00	35.00	35.00	5	6	7	5	8
Q-Cells	-	-	-	-	28.00	-	-	-	-	9
Photowatt	10.00	14.00	14.00	17.00	20.00	7	7	10	10	10
AstroPower	12.00	18.00	26.00	29.70	17.00	6	5	5	6	11
Total	166.10	246.80	336.24	476.92	632.43			-		
World total	201.30	287.65	390.50	561.77	744.08			-		

Source: Maycock (2004)

Sharp

With a share of 26.6% of total production, Sharp is definitely leading the global PV market. Sharp started with the development of solar cells in 1959 and introduced in 1980 the first calculators with solar cell batteries. The development of high-efficient multi-crystalline silicon solar cells started in 1992 and since 2000 Sharp is the number one producer in the world. Without any doubt, Sharp will continue to dominate the global market in the coming years. Since June 2004, Sharp sharply increased its solar cell production line to 315 MW with the start of production at the Shinjo Plant in the

Nara prefecture. Since February 2003, production capacity expanded from 200 MW – comparable to Table V- to 248 MW in November 2003 and finally 315 MW nowadays. This unseen expansion is motivated by the growing domestic and international demand (Sharp, 2004). In its press release on the Ninjo plants, Sharp refers to the German policies to promote PV systems and comparable programs in several US States. Sharp predicts that global PV demand in 2004 will top 1 GW. With expected cost reductions resulting from this expansion of capacity, other global players risk to face very tough price competition from Sharp.

Shell Solar

The headquarter of Shell Solar is based in Amsterdam but the company is in fact a global player with manufacturing bases in the US, Germany and Portugal. Shell Solar is an integrated company, active across the entire value chain of photovoltaics; from manufacturing of silicon components, solar cells and solar modules to selling of complete systems and installations. In addition, the company developed over time an extensive and highly experienced network of authorized distributors, dealers and installers around the world.

Total annual capacity of Shell Solar was estimated at 60 MW in early 2003 and expanded since then (see Table V). The company employs some 1300 people around the world and recently incorporated Siemens Solar. Shell invested millions of Euros in Shell Solar and is rather straightforward when it comes to the future of solar energy. According to Shell, solar power has the potential to produce 10 to 20% of the energy generated in the future but "*neither in Europe nor anywhere else major portions of the solar energy market can survive without subsidies at present. Its development is decided on in the political arena, jointly with corporations venturing to invest because they believe it will lead to a commercial line of business in due course* (Shell, 2002)".

Kyocera Solar

Kyocera Solar Inc. or KSI is part of the Kyocera group which was founded in 1959 in Kyoto by eight scientists. Ten years later Kyocera started to operate in the US and since then the North American operations of the group expanded to more than 5 000 employees engaged in the manufacturing and sale of a broad range of state-of-the-art, high-technology products in the United States, Canada and Mexico.

KSI is a vertically integrated high-tech company that serves the widely varying needs of customers for distributed solar electricity through two major market channels. Industrial customers, such as original equipment manufacturers, government organizations, utilities, corporate clients and institutions, are served directly with fully integrated system packages. KSI also serves a global network of more than 1 500 authorized distributors and dealers with components, packaged systems, engineering, technical support, project management, sales aids, literature and training. One of the most important products of KSI is the integrated MyGen™ Grid-tie Photovoltaic (PV) Power System, consisting of photovoltaic modules, a direct current to alternating current (DC-to-AC) power conversion device, DC wiring and protection, AC wiring and protection, lightning protection, component mounting and mechanical support (Kyocera, 2004).

BP Solar

The origin of BP Solar traces back to 1973 with the founding of Solar Corporation. Solarex later purchased Exxon's Solar Power corporation, and was purchased by Amoco Oil. In 1985 BP started to build manufacturing plants in Spain and acquired plants in Australia. In 1999, BP Solar and Solarex merged. In the US, BP Solar has 3 manufacturing plants, the BP Solar Headquarters, and various sales and support offices. BP Solar's operations in Europe range from technical sales and services groups in the UK to significant manufacturing operations in Spain to one of the largest sales and distribution networks in Germany. BP Solar has operations in almost every country in Europe.

BP Solar is European market leader in solar power plants. In September 2004, BP Solar opened its 'Geiseltalsee' power system in Saxony Anhalt. This project will produce approximately 4 MW what corresponds roughly to the average electricity requirements of some 1000 four-person households. For the future, an upgrade is 6 MW is planned.

In a recent speech Steve Westwell, BP Vice President for Renewable Energy and CEO of the global solar power business, stated : *"In the last five years, BP has already invested 500 million dollars in solar power activities. During the next three to* *five years, Germany, California and other parts of the United States and Spain will be significant growth markets. BP plans to increase its global production capacities from currently 90 to approx. 200 megawatt over the coming eighteen months (BP Solar, 2004)."*

2. Types of production

The vast majority of PV manufacturing output is used for grid-connected installations, mainly in the key markets of Japan, Germany and the US state of California. Table VI shows how this trend took off in 1999 and has dominated the sector since then. This grid-connected residential/commercial sector is estimated to have grown from 270 MW in 2002 to 365 MW in 2003. Japanese installations in 2003 increased by 200 MW, and German installations grew by about 120 MW. Smaller growth was in the US (38 MW) and the remainder of Europe (around 30 MW). Maycock (2004) further concludes that dramatic growth in market volume had an impact on prices. Thanks to the increase in the grid-connected market, the range of factory prices for single and polycrystalline silicon modules decreased to around US$2.70-3.25/Wp. Amorphous silicon and cadmium telluride modules were sold at prices of $2.00-3.00/Wp.

Table VI. World PV market by application area 1993-2003 (MW/year)

Application	**1993**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Grid-connected residential/commercial	2	7	27	36	60	120	199	270	365
Consumer products	18	22	26	30	35	40	45	60	65
World off-grid rural	8	15	19	24	31	38	45	60	70
Communications and signalling	16	23	28	31	35	40	46	60	70
PV-diesel, commercial	10	12	16	20	25	30	36	45	50
US off-grid residential	5	8	9	10	13	15	19	25	30
Centralized (> 100 kW)	2	2	2	2	2	5	5	5	8
Total (MW/year)	61	89	127	153	201	288	395	525	658

Source: Maycock (2004)

Crystalline silicon - both single and polycrystalline - continues to dominate the sector (see Table VII). Nearly 89% of the world's PV cell and module production in 2003 was based on sliced single crystal and polycrystalline silicon cells (660 MW). Despite the new plants announced in the thin-film sector, only 26 MW of amorphous silicon (A-Si) was produced (this is 3.4% of total production). In 2003, 4 MW of copper indium diselenide (CIS) was manufactured, along with 3 MW of cadmium telluride (CdTe). Sanyo produced over 30 MW of its amorphous silicon on crystal silicon slices. Single crystal and polycrystalline silicon production should continue to dominate the market for several more years.

Table VII. Cell/module production by cell technology in 2003

Technology	Production (MW)					Proportion of total
	US	Japan	Europe	ROW	Total	
Polycrystalline	13.42	271.23	114.50	60.65	459.80	61.79%
Single crystal flat-plate	68.00	44.17	71.15	17.15	200.47	26.94%
Single and polycrystalline total	81.42	315.40	185.65	77.80	660.27	88.73%
Amorphous silicon	7.10	0.01	7.70	3.00	17.81	2.40%
Amorphous silicon indoor use	0.00	5.00	0.00	3.00	8.00	1.00%
Amorphous silicon total	7.10	5.01	7.70	6.00	25.81	3.40%
Crystal silicon concentrators	0.70	-	-	-	0.70	0.10%
Ribbon (silicon)	6.80	-	-	-	6.80	0.90%
Cadmium telluride indoor	0.00	0.00[a]	-	-	-	-
Cadmium telluride outdoor	3.00	-	-	-	3.00	0.40%
Copper indium diselenide	4.00	-	-	-	4.00	0.54%
Microcrystalline Si/single Si	-	13.50	-	-	13.50	1.82%
Si on low-cost substrate	0.00	-	-	-	0.00	0.00%
A-Si on Cz slice	-	30.00	-	-	30.00	4.00%
Total	103.02	363.91	193.35	83.80	744.08	99.89%
Total indoor use (8.0 A-Si + 1.5 CdTe)					9.60	
Total terrestrial production					734.48	

[a] Matsushita dropped CdTe for calculators.

Source: Maycock (2004)

3. PV activities in the US

US cell/module production totalled 103 MW in 2003, a 14.6% decrease on the previous year. There were several reasons for this: the difficult year experienced by AstroPower prior to its bankruptcy; reduced production by BP Solar in the US following the expansion of its new plants in Asia and Europe; and changes in the US

BP Solar plant (the former Solarex), including larger slices and a new anti-reflection coating. Production by manufacturer is shown in Table VIII.

Table VIII. US PV cell/module production (MW)

Company	1996	1997	1998	1999	2000	2001	2002	2003
Shell Solar	17.00	22.00	20.00	22.20	28.00	39.00	46.50	52.00
AstroPower	2.85	4.30	7.00	12.00	18.00	26.00	29.70	17.00
BP Solar	10.80	14.80	15.90	18.00	20.47	25.22	31.00	13.42
USSC	0.60	1.70	2.20	3.00	3.00	3.80	4.00	7.00
RWE Schott (was ASE)	3.00	4.00	4.00	4.00	4.00	5.00	5.00	4.00
First Solar	-	-	-	-	-	-	1.00	3.00
Evergreen Solar	-	-	-	-	-	-	1.90	2.80
Global Solar	-	-	-	-	-	-	-	2.00
Other (including SunPower, Ammonix, Iowa Thin Film Technologies)	1.10	0.20	0.60	1.00	1.50	1.30	2.50	1.80
Total	35.35	47.00	49.70	60.20	74.97	100.32	121.60	103.02

Source: PV News, Vol. 23 No 3, 2004

Progress in thin-film commercialization

The 30 MW roll-to-roll amorphous silicon plant of United Solar Systems Corporation (USSC) produced 7 MW in 2003. The BP Solar amorphous silicon factory in Virginia and cadmium telluride factory in California were closed in late 2002. Shell Solar (formerly Siemens Solar Industries) shipped nearly 3 MW of CIS PV modules, while First Solar shipped 3 MW of CdTe modules and announced plans to produce 6 MW in 2004. Global Solar produced nearly 2 MW of CIS-on-steel modules. Iowa Thin Film Technologies produced about 100 kW for specialized small power applications. One major event in the US thin-film market was the joint venture between USSC and Solar Integrated Power, which introduced a new flexible PV roofing material. Over 5 MW of capacity is now installed on the roofs of commercial properties in California.

Installations increased 42%

Despite reduced production, US installations (of 40 W or more) increased by 42% from 44.4 MW in 2002 to 63 MW in 2003 (see Table IX). Most of the growth was in the grid-connected sector, from 22 MW in 2002 to 32 MW in 2003. Imported modules doubled to 18 MW, the majority of these coming from Japan.

Table IX. PV applications by market sector in the US (MW)

Application	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Grid-connected distributed	1.2	1.5	2.0	2.0	2.2	3.7	5.5	12.0	22.0	32.0
Off-grid industrial/commercial	3.3	4.0	4.4	4.8	5.2	6.5	7.5	9.0	13.0	16.0
Off-grid consumer	3.0	3.5	4.0	4.2	4.5	5.5	6.0	7.0	8.4	9.0
Central station	-	-	-	-	-	-	-	-	-	5.0
Consumer (< 40 W)	1.7	2.0	2.2	2.2	2.4	2.4	2.5	3.0	4.0	4.0
Government projects	0.6	0.8	1.2	1.5	1.5	2.5	2.5	1.0	1.0	1.0
Total installed in US	9.8	11.8	13.8	14.7	15.8	20.6	24.0	32.0	48.4	67.0
Imports	-	-	-	-	-	2.0	4.0	5.0	9.0	18.0
Exports	16.2	24.0	25.1	36.3	37.9	39.8	55.0	73.3	81.2	54.0
Total produced	26.0	35.8	38.9	51.0	53.7	58.4	75.0	100.3	120.6	103.0

Source: PV Energy Systems

In California, the installation of PV systems nearly doubled to 27 MW in 2003. The increase was brought about by a number of programmes and initiatives;

- The California PV programme involves several key players and unique assistance, with the state's PV 'buy-down' programme resulting in the installation of 12.3 MW of grid-connected residential and commercial PV systems.
- The Sacramento Municipal Utility District (SMUD) completed phase two of its PV Pioneer programme by offering subsidized PV systems to its customers at reduced prices. SMUD installed about 400 kW of PV systems in 2003; over 11 MW of capacity has been installed by SMUD in the last ten years.
- The Los Angeles Department of Water and Power (LADWP) PV programme - with subsidies as high as $5.50/W - resulted in 3.8 MW of newly installed PV systems in 2003. Cumulative installations by LADWP reached 7.5 MW.
- The California Public Utilities' renewable portfolio standards (RPS) programme with Pacific Gas & Electric, Southern California Edison, San Diego Gas and Electric, and Southern California Gas Co. installed 9.9 MW in 2003. Other Californian utilities and cities installed nearly 400 kW.

The government sector

PV serves a broad array of applications in this sector and many applications are considered to be 'emerging markets'. These include PV-diesel hybrid power stations that can ultimately serve remote sites or provide transportable power for emergency situations. The US Department of Defense funds the installation of about 0.5 MW per year and this has resulted in installed PV systems totalling over 3 MW. These systems are in applications ranging from remote sensors to large off-grid PV-diesel hybrid systems where utility power is not available or reliable. The Utility Photovoltaic Group (UPVG) programme has also carried out thousands of utility installations, amounting to over 9 MW in five years. Several thousand 'nearly economic' applications have been installed. The US Department of Energy subsidized these early applications with, on average, 25% of federal funds. No UPVG systems were installed in 2003, although several of the utilities that gained PV experience have installed PV under their state-mandated RPS programmes. Another important government programme is 'PV for Schools' in which federal and state programmes fund the installation of small grid-connected systems in schools for education and emergency power.

The on-grid distributed sector

Prior to 1999, this sector involved only a few 'early adopters', amounting to less than 2 MW per year. In 2003, this sector had grown significantly, and had 32 MW of new installations. Growth was primarily in the on-grid residential sector, and was primarily the result of state tax credits. California led the way, with over 27 MW of grid-connected systems installed in 2003.

Other important programmes included - but were not limited to - the 'PV for Schools' programme, and state programmes for renewable energy set-asides resulting from restructuring.

Other forms of marketing incentives included standard PV systems for new homes, offered through home-builders, by AstroPower, BP Solar and Shell Solar, and expanded in-store sales of packaged retrofit, grid-connected, AstroPower PV systems through the Home Depot chain of do-it-yourself stores.

Costs and prices

The installed cost of grid-connected PV systems decreased slightly as cash subsidies, especially in California, decreased from $4.50/W (AC) installed to $3.50/W. In this competitive environment, the installed prices dropped from around $8.00-9.00/W (AC) in 2002 to about $7.00/W in 2003 (see Table X); some volume systems were sold at low prices of $6.50/W,primarily to builders. These price reductions were made possible by continued low factory module prices for volume purchases (see Table XI) and reduced labour costs, owing to increased volume of installations.

Table X. US trends in system prices for grid-connected residential systems

Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Price (US$/W)	12.00	12.00	12.00	11.00-12.00	10.00-12.00	10.00-12.00	10.00-11.00	9.00-11.00	8.00-10.00	7.00-9.00	6.50-9.00	6.50-8.00

Table XI. Typical prices for single and polycrystalline silicon modules in US

Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Price (US$/W)	4.25	4.25	4.00	3.75	4.00	4.15	4.00	3.50	3.75	3.50	3.25	3.00

4. PV activities in Japan

Sharp continued its explosion in production to 198 MW in 2003 (nearly twice the total production of PV in the US), and announced plans for module assembly plants in Mexico and the UK. Both Kyocera and Sanyo continued their expansion, and said that they planned to more than double their production in the next two years. Sanyo continued to expand production of its very high-efficiency amorphous silicon on crystal silicon heterojunction cell (the HIT™ cell). Shipments of HIT product topped 32 MW in 2003. The Japanese Government's goal is to achieve production capacity of over 500 MW, with a domestic market of 250 MW per year and annual exports of the same amount by 2005. An estimated near-200 MW of grid-connected PV was installed in 2003. Table XII gives full details.

Table XII. Japanese PV cell/module production (MW)								
Company	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Sanyo	4.60	4.70	6.30	13.00	17.00	19.00	35.00	35.00
Kaneka	0.00	0.00	0.00	3.50	5.00	8.00	7.50	13.50
Kyocera	9.10	15.40	24.50	30.30	42.00	54.00	60.00	72.00
Mitsubishi Electric	-	-	-	-	12.00	14.00	24.00	42.00
Sharp	5.00	10.60	14.00	30.00	50.40	75.02	123.07	197.91
Hoxan	0.80	1.00	1.00	1.00	1.00	0.00	0.00	0.00
Canon	0.50	2.10	2.00	1.00	0.00	0.00	0.00	0.00
Matsushita	1.20	1.20	1.20	1.20	1.20	1.20	1.50	1.50
Mitsubishi HEL	-	-	-	-	-	-	-	2.00
Total	21.20	35.00	49.00	80.00	128.60	171.22	251.07	363.91

The Japanese PV production industry aggressively sought export sales during 2003, with the establishment of marketing organizations both in the US and in Germany. Several government-assisted projects were initiated in the developing world as well.

Residential PV dissemination programme exceeds goals

Begun in 1994, the Japanese PV Systems Dissemination programme (commonly called the '70,000 Roofs' programme) has now exceeded all its goals. The programme started with a 50% subsidy, that was decreased incrementally, reaching about 10% in the financial year 2003. Over 168,000 residential systems were installed in the period 1994-2003, with a total capacity of over 620 MW (see Table XIII).

The Japanese '70,000 Roofs' programme is now completing its last year of subsidies (see below). Over 25 000 applicants were approved between April 2001 and March 2002, and 38 000 applicants were approved between April 2002 and March 2003. 52 863 applicants were approved in the financial year 2003, leading to installations of over 200 MW.

Table XIII. Summary of Japanese '70,000 Roofs' programme										
Systems	**Financial year**									
	1994	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Number installed	539	1,065	1,986	5,654	6,352	15,879	20,877	25,151	38,282	52,863
Cumulative number installed	539	1,604	3,590	9,244	15,596	31,475	52,352	77,503	115,785	168,468
Capacity installed (MW)	1.86	3.916	7.536	19.486	24.123	57.693	74.381	91.00	141.00	201.00
Cumulative capacity (MW)	1.86	5.776	13.312	32.798	56.921	114.614	188.995	279.995	420.995	621.995

Source: Osamu Ikki, PV Activities in Japan (**ikki@rts-pv.com**). 1994-2001 data from the New Energy Foundation

Some aggressive pricing is expected from Japan in order to enter other growing markets. Prices for residential grid-connected PV systems installed in Japan have dropped: while 1995 prices were nearly $11/W, installed prices in 2003 were less than $6/W.The next two years will, however, be pivotal, as the explosive growth in the Japanese home market could slow down just as new factories come on-line. Consequently, export markets would be necessary to keep the industry healthy.

5. PV activities in Europe

European installations are estimated at 140 MW, with over 110 MW in Germany and 30 MW in the rest of Europe in 2003. Though Germany dominates the European market for installations, manufacturing is more diverse, with Isofoton and BP Solar manufacturing in Spain, and Photowatt in France. During 2003, PV cell and module production increased by 43% to reach 193.35 MW in 2003 (see Table XIV). RWE Schott and Isofoton rose to number one and two in Europe, respectively, with 38 MW and 35.2 MW of production. Q-Cells shot into third place with 28 MW, and Shell (Germany) moved into fourth with 25 MW. Photowatt and BP Solar (Spain) grew to 20 MW and 16.45 MW, respectively.

Q-Cells

It is quite possible that in 2004, the leading position in the European PV industry will not be taken by one of the incumbents but by Q-Cells. Q-Cells, located in Thalheim

(Sachsen-Anhalt in Eastern Germany), is an important newcomer on the PV scene. It is an independent producer that concentrates on key technologies in the photovoltaic field. The initial market entry by Q-Cells was through a major investment in 2001: a 12 MWp facility for the production of high performance polycrystalline solar cells. The capacity of the first line was successfully increased to 24 MWp in mid 2002. The second factory of Q-Cells began operating in 2003, giving the company a total output of 48 MWp and the commissioning of further production lines in 2004 is taking the overall capacity to 100 MWp.

To illustrate the industrial dynamics that rule the PV sector, it worth stressing that the first Q-Cells factory was built and commissioned in the record time of just six months. Also the construction time for a second and third, considerably larger, factory must be with 8 and 7 months close to a record. The factory has been designed with the most modern and proven technology, it includes a number of industry innovations and is highly automated. The production technology is based on fully automated multi-batch processes, in order to deliver maximum reliability and redundancy in the event of single machine down-time. A key feature of Q-Cells' production line is the quality management, where some of the most modern techniques have been incorporated to ensure product and process integrity.

Cell efficiency is key: Q-Cells was one of the first European industrial producers to offer solar cells exceeding 15 % efficiencies to its customers. Its best polycrystalline cells exceed 16.4 %, and Q-Cells offers commercial products with an efficiency up to 15.6 %. The mono-crystalline cells deliver efficiencies up to 17.8 %. The need for further increases is self evident for the company and will be essential to generate price and performance improvements. Technologically, the medium term objective is to improve cell efficiencies up to the current potential of around 17 % for poly-crystalline material and around 20 % for mono-crystalline material. As a pioneer in Europe, Q-Cells introduced the Q6 solar cell (6-Inch-Format/150 x 150 mm) in 2002, which sets a new standard and leads to further cost improvements. Q-Cells recently presented its newest product innovation: the 8-inch high performance photovoltaic cell made of multi-crystalline silicon. The performance generated by this solar cell with its edge length of 210 mm is 97 % higher than that of the 6-inch cell – the current standard product. Q-Cells already produced the cell with the highest performance in Europe with its Q6. At a cell density of 330µ the cell performance of the 8-inch cell is at least 6.4 Wp. It will be launched in the first quarter 2005.

The shares of Q-Cells are held by the management team, a number of private investors, a German bank and two international venture capital partners. Q-Cells has completed two financing rounds: the initial financing of ca. 15 million Euro for the first factory and a further 20 million Euro in a second round financing for the expansion of Q-Cells 1 and Q-Cells 2. For its development in 2004 the company will invest 20 million Euro. Q-Cells' revenues increased from 17.3 million Euro in 2002 to 100 million Euro in 2004. In November 2004, Q-Cells announced the further expansion of its production capacity from hitherto 170 MWp (megawatt peak) to in total 320 MWp. This expansion will create more than 100 new jobs in Germany and bring total employment by Q-Cells up to 450[18]. The preliminary work for the highly modern production line started in the last quarter of 2004. It is planned to put it into operation by the 2nd quarter of 2005. As a result of this expansion Q-Cells will be one of the largest producers in the sector worldwide (Q-Cells, 2004).

Table XIV. European PV production (MW)

Company	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
RWE Schott (Germany; was ASE)	2.00	3.00	7.00	10.00	16.00	24.50	38.00
Isofoton (Spain)	2.70	4.20	6.10	9.50	18.02	27.35	35.20
Q-Cells (Germany)	-	-	-	-	-	8.00	28.00
Shell (Germany)	-	-	-	3.30	7.50	9.00	25.00
Photowatt (France)	5.70	12.00	10.00	14.00	14.00	17.00	20.00
BP Solar (Spain)	11.30	4.50	5.00	9.16	12.16	16.70	16.45
Ersol (Germany)	-	-	-	-	-	9.00	9.00
Sunways (Germany)	-	-	-	-	-	4.50	4.50
Eurosolare (Italy)	2.50	3.20	1.50	2.30	4.00	3.00	3.50
Helios (Italy)	1.40	1.50	1.30	1.50	2.20	3.00	3.50
Intersolar (UK)	1.20	1.30	2.00	2.50	3.00	2.30	2.50
RWE Phototronics (Germany)	0.00	0.00	2.00	2.00	2.00	2.00	2.00
Free Energy Europe (the Netherlands)	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Konkar (Croatia)	0.80	0.80	0.80	0.80	0.60	0.60	0.60
Shell (the Netherlands)	2.00	2.00	2.00	2.20	2.80	0.00	0.00
Dunasolar (Hungary)	-	-	1.20	2.20	3.00	3.00	0.00[a]
Other companies	0.20	0.40	0.50	0.60	0.50	4.50	4.50
Total	30.40	33.50	40.00	60.66	86.38	135.05	193.35

[a] Dunasolar moved to Thailand in 2003.

[18] Total employment at RWE Schott is currently around 600.

Photovoltech

Table XIV does not include information on Belgian producers. It appears however that the young Belgian company Photovoltech will be among the largest European companies within 2 years. On December 16, 2004, Photovoltech's Board of Directors approved a decision to increase the photovoltaic cell production capacity of the company's plant in Tienen, Belgium, from 13 MWp to close to 80 MWp a year. When all permits are received, the new capacity will be commissioned by end-2005, with production gradually ramped up to full capacity in 2006. The expansion project will create close to 80 jobs. This growth will consolidate Photovoltech's position as a top-tier operator in the photovoltaic solar power industry in the European Union. The company will produce enough cells in a year to equip around 40 000 households, in response to strong growth in demand in the EU, especially Germany. Photovoltech was created in December 2001 by Total (42.5%), Electrabel (42.5%, including the interest held by subsidiary Soltech) and Imec (15%). Photovoltech holds an exclusive license to Imec technologies that offer significant advantages, notably in terms of cell efficiency and appearance. The project reflects the commitment of Total and Electrabel to this type of renewable energy, for which the outlook is very promising (Photovoltech, 2004a). Total and Electrabel are already commercially active in the field of solar energy through their respective subsidiaries Total Energie and Soltech.

Imec (Interuniversity MicroElectronics Center) is one of the world's leading research institutes, with a proven reputation in solar energy. Using state-of-the-art high-tech equipment, Photovoltech started production of multicrystalline silicon solar cells in November 2003. As a spin-off of Imec, Photovoltech has a variety of innovative technologies at its disposal. Its isotropic texturization production process delivers cells that combine an outstandingly uniform appearance with high efficiencies (up to 16% and more). These cells are commercialized under the brand name MAXIS.

The premium product in the MAXIS range is the MAXIS BC+ cell, a unique Back Contact Cell which offers enhanced visual appeal because there are no bus bars on the front. The 'metallization wrap through' process allows the electrodes to be passed through the cell. Besides the aesthetic advantage, module manufacturers are interested in Back Contact Cells for two reasons: by bringing the external contacts to a single surface, the cost of module assembly can be reduced and in addition, a higher packing density (and therefore higher module efficiency) can be achieved.

Photovoltech also manufactures and markets its own modules. The module portfolio with standard MAXIS cells goes up to 180 Wp with 72 cells (encapsulated cell efficiency 16%). Modules with MAXIS BC+ cells will be launched in 2005. Photovoltech’s modules are suitable for all applications: stand-alone installations and grid-connected systems. For applications where visual appeal is an important factor, Photovoltech’s Back Contact modules offer an excellent solution (façades, architectural projects, sunroofs,…). Due to the sustained and increasing growth of the photovoltaic market and strong demand for its products, Photovoltech aims to expand its capacity considerably and to continue to grow in the coming years. Photovoltech currently has a workforce of 52 people (Photovoltech, 2004b).

German PV programme reborn

It was the combination of two German support programmes that stimulated the tremendous growth in the German PV market - the '100 000 Dächer-Solarstrom-Programm’, which provided loans at a very low rate of interest, and the guaranteed rate (feed-in tariff) for all PV-generated power fed into the grid. The number of German PV installations qualifying for the feed-in tariff were estimated at nearly 120 MW in 2003, enabling Germany to exceed its goal of 350 MW installed. This program was open for private persons, households and small and medium businesses. Up to 5kWp installed a loan of 6 230 Euro per kWp has been foreseen, with a limit on the total loan set at 500 000 Euro (KfW, 2002).

Table XV. Feed-in tariffs under the revised German feed-in law

Site of installation	Tariff (Eurocents/kWh)
Undeveloped area	45.7
Roof (< 30 kW)	57.4
Roof (> 30 kW)	55.0
Facades (< 30 kW)	62.4
Facades (> 30 kW)	60.0

As the '100 000 Roofs' programme was coming to an end, and 2003 was the last year of both the low interest and the high price for PV electricity (about 45 Eurocents/kWh), the German programme was reborn, in January 2004, with a revised law. This law extends the buy-back rate to 45-62 Eurocents/kWh, depending on the type of installation. Table XV shows the new rate structure.[1]

6. PV activities in the rest of the world

PV production in the rest of the world in 2003 increased by 52% to 83.8 MW (see Table XVI).

Table XVI. ROW PV cell/module production 1995-2003 (MW)

Company	1995	1996	1997	1998	1999	2000	2001	2002	2003
CEL (India)	1.40	1.60	2.00	2.00	2.10	1.50	1.70	1.50	2.00
Sinonar (Taiwan)	-	2.50	2.50	2.60	2.00	3.00	3.00	3.00	3.00
BHEL (India)	1.15	1.00	1.00	1.00	1.00	1.00	1.50	1.50	2.00
BEL (India)	-	-	-	-	-	-	-	1.00	1.00
RES (India)	0.70	1.00	1.00	1.20	1.20	1.00	1.00	-	-
Heliodinamica (Brazil)	0.40	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reil (India)	0.70	0.70	-	-	-	-	-	-	
CHINA	1.50	1.50	1.50	1.60	2.00	2.50	3.00	8.00	9.00
Webel (India)	-	0.65	0.70	0.70	1.20	1.50	1.20	3.00	4.50
Udhaya (India)	-	0.50	0.50	0.50	0.50	0.50	0.50	0.95	0.95
BP Solar (India)	-	-	-	3.80	4.00	6.46	8.06	13.10	14.11
BP Solar (Australia)	-	-	-	5.10	5.50	5.76	6.96	8.40	26.24
BP Solar (Hong Kong)	-	-	-	-	-	-	1.30	3.30	0.0
BP Solar (Malaysia)	-	-	-	-	-	-	0.70	1.30	0.0
Motech (Taiwan)	-	-	-	-	-	-	3.50	8.00	17.00
Maharishi	-	-	-	-	-	-	-	-	3.00
Other[a]	0.50	0.20	0.20	0.20	0.20	0.20	0.20	2.00	1.00
Total ROW production	6.35	9.75	9.40	18.70	20.50	23.42	32.62	55.05	83.80

[a] Includes Microsol and Harbin Chronar.

Source: PV News, Vol. 23 No. 3, 2004

Taiwan's Motech reported over 100% growth to 17 MW. Motech's solar cell factory is located in the Tainan Science-Based Industrial Park. Motech (founded in 1997) began mass production of crystalline silicon solar cells in November 2000. Annual production was 3.5 MWp in 2001 and 8.0 MWp in 2002. The projected total production in 2003 is 18 MWp. Planned further expansions will bring Motech's solar cell production capacity to 50 MWp by the end of 2004. This projection indicates the

increasing competition that European and other major players will face in the coming years. Interestingly, the CEO of Motech's Solar Electricity Division, Dr. Simon Tsuo worked in the past at the U.S. Department of Energy's National Renewable Energy Laboratory in Golden (Colorado). Motech began production of single-crystal solar cells in addition to Multi-Crystal Solar Cells. The average efficiency of Multi-Crystal Solar Cells reached 14.7% and Single-Crystal Cells reached 15.5% (Motech, 2004).
China's production is estimated at 9 MW (although unconfirmed reports put this figure at 10 MW). Much of the growth in ROW production was the result of increases by BP Solar in India (14.11 MW) and Australia (26.24 MW).

7. Conclusions

The global PV is strongly growing and the most important Japanese and European companies have ambitious expansion plans. Further increases of cumulative production will lower future prices and this process can have problematic consequences for the least efficient producers. A market shake-out in 2005 or 2006 would be no surprise.
In their expansion plans, most companies refer to the German market. This again illustrates the fragility of the current PV market. The reverse image of this situation of dependence is that the European PV market would really explode when a few other countries would follow Germany’s example. In Japan as well as Europe, there are currently no problems in doubling or even tripling PV production capacity. The Belgian case of Photovoltech illustrates that Belgian engineers and technicians have the skills to play a significant role in the global market. Q-Cells managed to build new plants in 6 to 8 months. PV installations have the advantage of offering flexibility to its buyers but apparently the same flexibility is found with respect to constructing new PV plants. These are all indicators that policymakers really can move this industry with targeted incentives. Europe has the technical skills, abilities and networks to dominate the PV market in the coming decade. But this will only happen when national programmes are launched to create the markets.

C. Policy design and argumentation

In this part, the essential steps in the pro-PV policy process of Germany are briefly discussed. We have to conclude that technological progress is only one side of the story: institutional change is at the heart of the policy process. In the next section, a strategy to develop new climate friendly technologies such as PV is positioned in the current emphasis on cost-effective and short-term 'hot air' mitigation options in climate policy. PV clearly plays a role in long-term climate policy but we should be aware that current institutions and 'soft' instruments such as low energy taxes will never trigger massive PV investments. On the contrary, the further and expanded use of current climate policy instruments – environmental taxes as well as emissions trading and green certificates- even risk to detract investment funds from radically new renewable technologies to the most mature renewable technologies such as wind energy.

We conclude with an overview of possible policy options to accelerate the diffusion of residential PV. Most countries will favour a mixture of instruments and strategies but our analysis suggests that especially technical regulation in the form of building standards can yield most advantages at a very low cost. Compared to annual price increases in the residential sector, mandatory investments in PV-systems only marginally impacts the price of apartments in PV-equipped buildings. An essential advantage of technical regulation is the enforced development of national PV-institutions among all involved stakeholders.

1. Industrial take-off: the case of Germany

Jacobsson and Lauber (2005) argue that policymaking is not a 'rational' process but rather one that appears to be based on visions and values, the relative strengths of various pressure groups and on deeper historical and cultural influences. In countries like Germany, Denmark and Japan, policymakers decided to pursue comprehensive strategies to develop renewable energy technologies. A complex and unpredictable political process preceded this pro-renewable position. In most other developed countries, mainly good intentions have been formulated so far.

The case of Germany is revealing from many respects. After extensive periods of experimentation with wind and solar technologies, the stock of installed capacity in

Germany started to grow strongly between 1995 and 2002. This development can be the first phase of an industrial life cycle; the take-off of the long-term diffusion of renewable technologies. There exists a broad literature on these initial phases which are characterized by an extremely high degree of market uncertainty (in terms of competing designs, new entrants, regulatory changes, etc). Jacobsson and Lauber (2005) distinguish four key conditions for this formative stage to emerge:

1. Institutional change is at the heart of the process (Freeman and Louca, 2002). This is of course a broad policy field, ranging from scientific to educational policies. It implies that prior investments in knowledge formation take place before market opportunities are created. Only countries with relevant technological traditions will be able to exploit new global market opportunities for new renewable technologies. Given the recent creation of new corporations in the PV industry, the latter condition is certainly fulfilled in Belgium. This is however not a reason to restrain further basic R&D investments in new solar technologies. The institutional infrastructure is of course much broader and includes economic regulation, tax policy and industrial policy. New firms need to find support in the existing institutional infrastructure, otherwise their growth opportunities will be obstructed. Van de Ven and Garud (1989) were the first to claim that firms not only compete on the markets for goods and services, but also to gain influence over the institutional framework. In terms of PV development, an institutional framework that clearly supports a transition towards more sustainable energy technologies is an essential precondition. Support for new industries therefore should be as transparent as possible and based on a long-term perspective (10 years and more). In addition, crucial aspects such as access to the grid and feed-in tariffs for PV electricity producers should be guaranteed and communicated in a way that reduces uncertainty. Annual regulatory changes create unnecessary levels of uncertainty.
2. Initial markets will not emerge themselves but need to be created for a new technology. In the formative phase, niche markets are essential to demonstrate the viability of the technology and to help building a constituency behind a new technology. Technical regulation provides the easiest and most direct way to create new markets. New regulation can impose PV modules on the roof of new commercial and residential buildings with a total market value exceeding a

specific threshold. This type of regulation will be further elaborated in the next sections. Indirect market creation can result from making other alternatives more expensive. When fossil-based electricity is highly taxed, the relative position of renewable energy is improved. But given the weak prospects for higher energy taxes in the near future, technical regulation should be considered as first option. This is especially relevant for Belgium where initial PV-markets are modest and uncertain.

3. A new technology will only become successful when it is backed by a broad constituency. Institutional back-up for the new technology can be provided by other businesses – also from other industries- and organisations such as universities, NGO's, labour unions, pressure groups, writers and journalists. Only a respected PV coalition can engage in wider political debates and secure institutional alignment. Jacobsson and Lauber (2005) argue that the development of joint visions of the role of that particular technology is a key feature of that process. From this respect, the future of PV in Belgium will only be secured once policymakers set clear targets for the diffusion and future role of PV. Private investment plans are preferably based on clear or at least quantifiable market prospects.
4. New firms should enter the new industry in order to strengthen the political coalition of a specific technology. The more people depend on a new industry (as supplier or employee), the less easy it is for policymakers to neglect the industry or to disadvantage the industry with regulatory changes. It is simply unthinkable that Denmark, Germany or Spain would ever take measures that seriously endanger the viability of their own wind energy industries[19]. In those three countries, investment companies and banks are aware of the power and significance of the wind industry and this will positively influence their decision to provide capital to new initiatives. And access to capital is essential for new companies. From the other conditions, we know that new firms will only enter the market when an initial market exists and has already some institutional back-up.

[19] As no market can be sheltered from internal and external market dynamics, producers in these countries can also be confronted with drastic regulatory changes. Long-term survival depends on adaptation to new circumstances, even in countries with a clear pro-renewable strategy.

A take-off of PV into a rapid growth phase may occur when investments have generated a large enough and complete enough system that can develop in a self-sustaining way. Once started, a chain reaction of positive feedback loops can set into motion a process of cumulative causation.

The case of Germany

Until the end of the 1980s and in fact beyond, renewable energy faced in Germany a political-economic electricity supply structure that was largely hostile (Jacobsson and Lauder, 2005). Large utilities relying on coal and nuclear energy dominated the market and were strongly opposed to all small and decentralized production. R&D funding for nuclear power and coal dwarfed that of renewable energy technology. In 1982, total energy R&D in Germany totalled over 2 billion Euro, of which 0.0025% went to wind and PV R&D. Part of the latter fund were even devoted to demonstration projects that were set up to prove wind energy was not viable. Is it then surprising that technological evolutions in renewable energy technologies were rather modest? The Chernobyl accident came at a time when several politicians started to ask questions with the pro-nuclear policy of ‘gentle repression’ that has been pursued so far. Chernobyl meant the end of German nuclear R&D and gave a boost to pro-renewable pressure groups. Opposition against renewable energy inside ministries however was very tough. The Ministry of Economic Affairs which supported in the past huge subsidies for coal and nuclear energy, now resisted all demands for market formation with the remarkable credo that new energy technologies had to prove themselves in the market without subsidies.

Around 1990, around 1.5 MWp solar capacity was installed in Germany (mostly under the solar demonstration project that started modestly in 1986). Although the installed capacity was modest, four firms entered the market (among which AEG, MBB and Siemens) and a range of organisations started to defend the case of solar energy. Next to business associations like the German Solar Energy Industries Association, Greenpeace and more importantly the *Öko-Institut* became very active. The *Öko-Institut* even delivered regulatory proposals that were later more or less adapted into the renewable energy policy laws. This growing and efficient constituency, together with the rise of the Green Party, made it impossible for German policymakers not to support renewable energy in the early 1990s. The concept of ‘cost covering payment' has been forwarded by the constituency in 1986 and 1989 and was later applied in various Feed-in Laws at federal and local levels. Interestingly, the Feed-in Laws of 1987, 1988, 1998 and 1990 were severely counteracted by the Ministry of Economic Affairs but these efforts failed. The Feed-in Law required utilities to connect generators of electricity from renewable energy technologies and buy the electricity at a rate which for wind and PV amounted to 90% of the average tariff for final customers. In addition, large demonstration cum market formation programmes initially guaranteed a payment of 4 Eurocents per kWh renewable electricity produced. As already discussed, a later demonstration programme for PV was the 1 000 roofs programme.

From the beginning and especially with the take-off of the wind turbine industry in Germany, the big utilities started to attack the Feed-in Laws both politically and in the courts. Even a complaint with DG Competition was lodged, invoking violation of state-aid rules. The German Ministry of Economic Affairs than proposed to reduce the feed-in rates with the reduction of the production cost from renewable technologies and later DG Competition followed this argument. These political debates however impacted investors' confidence and this explains the stagnation of the renewable energy market in Germany between 1996 and 1998. In 1997, the Feed-in Laws were incorporated into the Act on the Reform of the Energy Sector. Feed-in rates were not reduced dramatically. The proposals to do so led to massive demonstrations bringing together metalworkers, farmer groups, church groups and environmental associations.

After this removal of uncertainty, larger firms entered the wind turbine industry. For PV, the 1 000 roofs programme was successful but could not justify investments in new production facilities. The proposal for a 100 000 roofs programme by Eurosolar in 1993 was not supported by the government coalition at that time. The German PV industry has been saved by the municipal utilities. Local pro-solar activists petitioned local governments to enter into cost-covering contracts for PV electricity. After much effort, most *Länder* allowed these contracts, especially since PV electricity remained a marginal business at that time. This process is known as the Aachen model. In a later phase, some states decided to subsidize solar cells for special purposes, e.g. schools. Of equal importance were the efforts by Greenpeace Germany to collect several thousand orders for solar rooftops. All these efforts guaranteed that the German PV industry did not disappear at the end of the 1 000 roofs program.

The growth of German PV producers – Siemens already started production in the US - made the public aware of the threat of ASE to leave Germany when no local PV market was ensured. After dialogue with policymakers, ASE decided to expand in Germany and this example was followed by Shell in 1998.

In January 1999, a 100 000 roofs programme with low interest loans for about 350 MW was started. For the sake of speed, the programme took the form of a decree by the Ministry of Economic Affairs and only after strong protests by parliamentary groups, this ministry withdrew its bureaucratic obstacles. This programme was initially not a big success since everyone was waiting for a revision of the Feed-in Law with the Renewable Energy Sources Act. This new act refers to the polluter pays principle and in the memorandum we find that *"conventional energy sources still benefit from substantial government subsidies which keep the prices artificially low"*. Under the new law, the rates of the tariff scheme were guaranteed to investors for 20 years. Preferential rates were guaranteed until a specific cumulative capacity was reached. These ceilings needed to be raised in 2002 due to the large expansion of renewable energy in Germany.

In 2002, the Green Party could secure the transfer of the competency of renewable energy from the Ministry of Economic Affairs to the Ministry of the Environment. But around that time, a new enemy emerged with the coal and nuclear interests that for the first time feared that the success of renewable energy could eventually lead to the displacement of nuclear and coal plants, especially at a time with no expected growth of electricity demand. So far the renewable industry proves strong enough to cope with the protectionist challenges for the coal/nuclear coalition. This is clear illustration of the significance of a broad constituency.

In 2002, the German government announced that by 2050 renewable energy (including imports) is envisioned to contribute above 60% of total electricity demand (Bundesregierung, 2002). In this scenario, electricity from renewable energy sources is expected to require regulatory support until about 2020-2030. After 2030, renewable energy is expected to outperform conventional energy.

2. PV and the near-term versus long-term strategic trade-off

We already referred to the avoidance of external effects as a major advantage of PV. The potential of photovoltaics extends beyond the further diversification of energy technologies. In addition, PV can play an important role in the long-term development of climate policy. Due to the complex nature of climate policy, it is useful to distinguish between strategies and options for the short, medium and long term.
In principle, there are three climate policy strategies;

1. adapt to future climate policy changes;
2. reduce greenhouse gas emissions in the near future (up to 2020);
3. reduce greenhouse gas emissions in the far away future (starting in 2030 or 2040).

Option 1 is not acceptable for developed countries because they created – although not intentionally- the climate problem and have the technologies and resources to transform energy structures. Conclusively, developed countries should act according to their responsibility and show international leadership. Option 3 is rarely considered as a separate policy option although this goal obviously is in line with Article 2 of the UNFCCC[20]. Carbon cycle models project that the avoidance of too high atmospheric concentration levels of CO_2, e.g. at a level of 460 ppm, allow a further increase of global emissions up to 2025. Between 2025 and 2050, a significant reduction effort is necessary (Fetter, 1999). A similar conclusion is formulated in a recent policy advise by the Belgian Federal Council for Sustainable Development (Federale Raad voor Duurzame Ontwikkeling). So far, the international community selected option 2 with a strong emphasis on reducing greenhouse gas emissions by the year 2012. With the entering into force of the Kyoto Protocol in February 2005, especially European countries have no time to waste and are (desperately) allocating resources to buy hot air from Russia. Economists claim that buying hot air provides the most cost-effective option for meeting the Kyoto target by those countries that negotiated a very bad deal at the 1998 Burden Sharing Agreement (amongst them Belgium and the Netherlands). This is however a very short-sighted view on a very complex problem. The focus on

[20] The goal of the UNFCCC is the stabilisation of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system (UNFCCC, 1992).

hot air takes away resources that could otherwise have been invested in new technologies and processes to lower energy use or greenhouse gas emissions. The problem with hot air is that its existence provides an argument for many policymakers to do nothing and just send the cheque to Moscow. But what after 2012, especially in a country that wants to phase out nuclear energy?

In the negotiations for the post-Kyoto Protocol[21], Russia will not obtain a similarly generous deal. The only outcome of post-Kyoto negotiations is that real reductions of greenhouse gas emissions cannot be further postponed. There are two strategies to reduce emissions. Firstly, technological strategies based on government-funded basic R&D can aim at developing low-carbon technologies at acceptable costs, and secondly technical standards and price instruments can target current energy use and hence create a shift towards more sustainable technologies. The latter option is probably more an hypothesis than an effective option. First of all, technical standards are the result of negotiations between industries and policymakers. There is a powerful constituency defending the current carbon lock-in what renders it very unlikely that drastic technological standards will ever be implemented. The same constituency succeeds in preventing the installation of drastic energy taxes or other charges that will change behaviour. Policymakers fear the economic consequences of measures that really reduce energy demand. Therefore, we risk to end up with soft price instruments like low – if noticeable at all- carbon taxes and technical standards that pose no challenge at all. Both provide only weak incentives to develop innovative technologies. Too low price incentives will not lead to typical cost-effectiveness benefits that are associated with economic instruments for environmental policy. In this context, the only remaining alternative is the development of new low-carbon technologies such as PV. However, the current policy framework is focusing on the cost-effectiveness of short-term mitigation option while long-term solutions – not to mention the essential radical transformation of energy systems- is hardly considered. The same conclusion is reached by Sanden and Azar (2005) in a forthcoming paper ; ”*There is a risk that society in its quest for cost-efficiency in meeting near-term emissions targets, becomes blindfolded when it comes to the more difficult, but equally important issue of bringing more advanced technologies to the shelf.*”

[21] These negotiations are planned to start in 2005. The first exchange of information and preparation took place during the recent COP in Buenos Aires (December 2004).

This observation does not imply that price instruments have no role to play in the future development of climate policy. Especially strong price incentives are essential to control energy demand. Sanden and Azar (2005) even argue that the absence of mature carbon neutral technologies follows from the absence of strong industrial actors in favour of a carbon tax. With respect to the market attractiveness of PV, the current climate policy taxes do not close the current price gap as presented in Part I. Higher energy or CO_2 taxes – e.g. a tax rate of 70 US$/ton carbon – would make wind, biomass, natural gas and possibly light water reactors (LWRs) competitive (Sanden and Azar, forthcoming). This high tax would however not make PV competitive. To make PV competitive on most grid-connected markets within one year, a extremely high carbon tax of around 1000 US$ per ton carbon would be needed[22]. Conclusively, price instruments can create attractive markets for the most mature set of renewable technologies like wind energy. This new market situation can redirect renewable investments funds from sectors like PV towards additional wind capacity. Conclusively, the gradual increase of price incentives will not promote the diffusion of radically new low-carbon technologies (PV, fuel cells) and energy vectors (hydrogen). For these reasons, other policies that are complimentary to economy wide price incentives are crucial. We should also be aware that the technologies that are now considered as competitive all have a history of massive (and eventually) ongoing subsidisation. Historical fossil fuel and nuclear technology subsidies are extremely high but we should also not forget that gas turbines benefited from spill-over effects from military R&D of jet engines since World War II and onwards.

In this context, Sanden and Azar (2005) stress the ongoing reductions in energy R&D. This reduction is mainly due to the dismantling of nuclear and coal research while funds for renewable R&D remain at a very low level. In the US public energy R&D peaked in 1979 at 7.5 billion USD (1995) and is now down at 2.3 billion USD. With lower investments in technology development, the prospects for radical new technologies are limited. In addition to R&D policies, market creation can be of equal importance for the further development of PV. Both strategies have (dis)advantages but the current focus on short-term cost-effective mitigation does not provide at all incentives for the take-off of PV. We can only conclude that pro-PV policies are

[22] Even this extremely high tax level would not guarantee the commercial success of PV. Other low-carbon technologies less expensive than PV but more expensive than wind energy will benefit more from this tax regime than PV.

essential for the long-term effectiveness of climate policy. The further growth of wind energy will not be sufficient to lower greenhouse gas emissions without significant reductions of energy demand. Other low- or no-carbon energy technologies are simply indispensable for the future. Not investing in PV risks to increase the cost of future climate policy reduction targets.

3. Accelerating residential PV expansion; an overview of policy options

With energy prices not reflecting historical subsidies and external costs, the price disadvantage for PV installations will remain problematic. This section presents several policy options for the needed near-term PV expansion. In this section we focus on PV systems for new constructions. Although PV systems can be either incorporated into new homes or retrofitted onto existing homes, retrofitting makes it very difficult to realise the scale economies that are available to homebuilders. These are the most important advantages for new homebuilders:

- low equipment prices can be negotiated by purchasing in large quantities;
- stable relations can be developed with architects, electricians and roofers to optimize the design and installation of standard PV roofing packages;
- new houses can be sited and designed to ensure good solar access and easy installation;
- interconnection costs can be mitigated by developing relationships and standard costs with utilities and regulators;
- PV can be incorporated as a standard option in marketing materials for new homes (Duke, *et al*., forthcoming).

1. tax deductions/subsidies for PV installations or home mortgage interest deduction

Tax and mortgage deductions as well as direct subsidies are widely used instruments to promote the expansion of PV (in Europe, Japan and the US). Obviously, direct subsidies bring the highest costs for government budgets. Tax and mortgage deductions are mostly limited and can be spread over time. The problem with these options remains that profitable PV investments are never guaranteed[23]. Only very motivated house-owners with enough additional resources will invest in PV. In those countries with successful PV programs such as Germany and Japan, other support mechanisms like local subsidies and /or preferential tariffs were very helpful to ensure PV take-off. The most important instrument to support PV is the use of net-metering or the ability to sell PV-produced electricity to the net.

2. net metering or feed-in laws

With net metering, the house-owner can run the meter backward when PV system output exceeds the electricity needs of the building. When PV electricity is valued at retail electricity prices, the installation is generating at return during the operational lifetime. But given the underpriced retail electricity prices, especially PV net metering at prices that significantly exceed retail prices can provide an enormous boost to the PV market. Duke *et al*. (forthcoming) calculate that a 4 kWp system produces 5500 kWh/yr – for typical US insolation (1 800 kWh/m^2yr) and a 77% system efficiency- what is about half of average annual electricity consumption of US households. In Belgium with a lower insolation but also with a much lower average annual electricity consumption by households, a smaller 3 kWp can in principle produce more than half of annual consumption. From this setting, attractive net metering prices can provide a strong incentive to opt for PV installations with higher capacity than strictly needed. Furthermore, the ability to sell PV electricity brings many advantages. PV added to the grid can displace the most costly alternative power sources on the electricity supply system. Because of the strong correlation between peak PV output and the hourly demand for electricity[24], PV can in the long-run avoid the construction of new central-station peaking power plants.

The instrument of net metering is generally regarded as a temporary instrument in order to help launching the PV market. The sudden reversal of net metering / feed-in policies or the risk for a sudden reversal will reduce investors confidence. To lower this risk, house-owners will invest in smaller PV installations. Therefore, all the

[23] Only subsidies up to 75% of the investment costs can guarantee profitable PV investments for the house-owner.

[24] During the working week many houses with PV installations are empty between 8 AM and 6 PM, what allows the selling of PV generated electricity at that time. In the weekends, commercial buildings and most public building are also empty, allowing the production of PV electricity for the grid.

characteristics of net metering policies should be carefully communicated to possible investors:

- how long will the support measure exist?
- who can sell PV electricity to the grid?
- is there a cost to establish access to the grid?
- what is the price or the foreseen price evolution for PV electricity sold?

It is normal that over time the favourable prices for selling PV electricity will fall. The take-off of the global market will create significant reductions of the cost of PV installations and hence partly close the price gap. This evolution is on itself not a reason the gradually phase-out net metering incentives since the avoided external effects will be more important with supportive PV policies. Given the expected lifetime of a PV installation, a projection of the feed-in price for 20 years is essential to gain investors confidence.

The calculation of the precise net metering or feed-in tariff is very specific for each country and depends on existing electricity prices, average insolation and the use of other policy instruments to support PV. Quite obviously, the use of attractive net metering –without other supportive measures- is the least expensive strategy for policymakers. Established electricity companies will present their objections but one can be sure that they prefer high feed-in tariffs above realistic externality taxes on electricity. High energy or electricity taxes risk to reduce aggregated electricity demand – and hence the market value of electricity companies- while the feed-in of PV electricity will have a hardly noticeable impact on the profitability of electricity companies.

3. building standards

Technical regulation provides another inexpensive option to launch the PV market. In Belgium, as well as in most other countries, property prices for houses and especially apartments strongly increased during the last decades. Over the last three years, the average price increase was 8% per year. Real estate prices in and near Brussels skyrocketed. Further price increases are projected, although not for all real estate categories. Policymakers should make use of this attractive evolution to launch residential PV installations. Direct results can be obtained by the use of technical standards.

Let's assume for the sake of illustration that policymakers enact a new building standard for new buildings- residential as well as commercial- with an estimated market value of more than 500 000 Euro and impose for these buildings a PV installation of at least 1 kWp per 150 000 Euro of expected total market value. Depending on the roof surface, an upper limit on installed PV capacity should be established[25]. We then assume that the market value of a planned building with 15 small apartments in a geographical area with relatively modest prices is around 700 000 Euro. Starting from a production cost price of 3.5 Euro per Wp, a 4 kWp installation for this building will cost around 14 000 Euro. This is a high price, net of subsidies or favourable feed-in tariffs. This amount should however be balanced to the total market value of the building. When the costs of the PV installation are fully transmitted to the buyers of the apartments, the price of the average apartment will increase from 46 666 Euro to 47 599 Euro. This is a price increase of 2%. When the same building would however be located along the coast line or in the heart of Brussels, the market value of the new building would be much higher. Assuming a market value of 2 100 000 Euro, an installation of in principle 14 kWp will be installed. The cost of this installation will be 49 000 Euros. When this additional cost is for 100% passed to the buyers of the apartments, the average price will increase from 140 000 to 149 800 Euro. The technical standard generates a price increase of 1% for each individual buyer of an apartment in the building. The two examples show that the price increase from the imposition of PV installations is marginal when compared to the annual real estate prices increases. The apartment prices in the latter example are not at all exceptional. Currently, new apartments with a surface of 100 m^2 are sold along the coast line for prices up to 250 000 Euro and more (depending on location, etc). For commercial buildings with even higher prices, the consequences of the mandatory standard are very similar.

New regulatory initiatives like the proposed building standard should consider existing practices and requirements. Project developers should still be free to select

[25] An alternative is not to establish this upper limit but to force architects to integrate PV modules in the facade of the building.

other technological options to reduce energy use and greenhouse gas emissions. When the energy efficiency performance of a new project is outstanding –measured against a quantified benchmark- one can argue that the obligation to install PV modules will trigger excessive financial, administrative and organisational burdens. However, when the new project hardly meets minimal requirements in terms of energy efficiency performance, the obligation to install PV modules will provide a strong incentive for the project developer to consider several options to reduce net-energy needs. When other options make it possible to reach an outstanding energy efficiency performance, the project developer should be free to select want he wants. When nothing happens, the obligation to invest in PV should be enforced.

In addition to the advantage of direct market creation, we can provide three additional arguments for the imposition of this mandatory PV installation standard for new buildings:

1. The mandatory standard forces all involved parties – project developers, architects, electricians, roofers, sales people, etc – to establish more or less stable relations to lower the time cost of integrating PV installations in the total project. In the literature on technological take-off, this formation of institutions is essential. The standard simply makes it impossible for architects to neglect the integration of PV installations.
2. Project developers rarely become owners of their own projects and many house-owner did buy a house that was build by others. A PV installation has an investment cost next to an operational cost. With attractive feed-in tariffs, there are even operational benefits. Project developers want to sell their buildings at attractive prices and will therefore not consider the integration of PV installations if their competitors don’t follow (although there are exceptions, especially with very expensive projects). The mandatory standard as such levels the playing field. Without the mandatory standard, the individual buyer of an apartment does not have the ability to demand for a PV installation. This request would strongly increase total project costs as well as the total cost of the apartment (when this individual will have to pay for the complete installation). A negative consequence of the mandatory standard is of course the restriction of choice for future project

developers. However, when project developers foresee other sustainable energy systems, the obligation to install a PV system can be withdrawn.

3. In the initial phase of implementation, this mandatory standard will confront project developers with several logistic and practical problems. This will imply frequent interactions with PV suppliers. Therefore, we can assume that this standard will provide a boost to especially Belgian PV firms since these are best aware of local construction practices and are best located to provide flexible solution to urgent construction problems. Since competition policy makes it impossible to require that local project developers buy modules from local producers such as Photovoltech, the advantage of local knowledge and flexibility should be considered as one of the few alternatives to support local suppliers.
4. The building standard shifts the financial burden of a pro-PV technology policy to investors in new real estate projects. From a social policy perspective, this group clearly has the ability to carry the financial consequences of the technology policy. Other policy alternatives such as subsidies are financed by general tax revenues and hence have a indirect impact on low-income groups.

Only a few Belgian project developers already integrate PV installations in their recent constructions. In its ‘Commodore’ project in Oostende, Groep Versluys did foresee solar electricity for the common areas such as the entrance hall. The Commodore building is located at the Albert I Promenade next to the beach and the price for each apartment probably exceeds 350 000 Euro. With nine floors and around 8 apartments per floor, the total value is this building is that high that the additional PV investment cost is simply negligible. In its publicity, Groep Versluys explicitly mentions the benefits – here low fixed costs for the common areas in the building- from the PV installation for the buyers of the apartments. This illustration shows that at least some Belgian project developers are aware of the benefits of PV and are able to sell it to (rich) clients that probably value the positive characteristics of solar technologies.

The mandatory standard can create a very promising initial market. The potential impact of the standard is high. Once 500 projects installed each 10 kWp, a generating capacity of 5MWp is created. If we optimistically assume that each year 500 projects will be completed, after 10 years a minimal Belgian PV-capacity of 50 MWp is realized. As a matter of comparison, the largest European PV company – Shell Solar- produced in 2003 modules with total capacity of 52 MW.

Furthermore, we need to stress that this type of technical standards has no cost for government budgets. To the contrary, the measure will generate incomes. The simple announcement of the measure can lead to a modification of existing investment plans. Current expansions by firms like Q-Cells and Photovoltech suggest that an output increase by 1.5 MW creates one full-time highly-skilled job. In addition, new jobs are created for roofers, electricians and other involved parties on the field. Of equal importance, these jobs will not replace existing jobs.

Finally, a more symbolic advantage of the measure would consists of the additional exposure to Belgian ambitions to contribute to the gradual transition to a low-carbon economy.

D. Conclusions

The PV installations that currently dominate the market still face a significant cost disadvantage between 10 and 15 cents per kWh electricity produced. This cost disadvantage can be explained by historical evolutions and should not be confused with technological inferiority of PV modules. The current electricity price from fossil-based power plants and nuclear plants excludes enormous historical and ongoing subsidies that made these technologies competitive, as well as the important social or external costs from fossil-based electricity production. When social costs are added to private production costs, the cost disadvantage of PV is reduced but not eliminated. With the most modern types of fossil-based power plants, the remaining external costs – other than external costs from greenhouse gases- are relatively low. Even a perfect and complete internalisation of external costs will not make current PV technologies competitive. This is however a static view on an evolving technology.

The global PV market grows by some 30% each year and this evolution will generate important cost reductions in the future. Sanden (2004) calculated that PV can become competitive to fossil-based electricity after some 20 years of further strong growth. There are however no guarantees that the progress ratios or learning ratios will remain identical over the coming decades. Green (2003) presented evidence of strong reductions in learning effects for gas and wind turbines. When the same phenomenon takes place for PV, competitiveness will be further postponed.

Cost competitiveness is however but one factor in a complex analysis that is currently dominated by engineering-economic considerations. Our future energy systems need to adapt to new market realities. Reserves of fossil fuels are limited and price increase are inevitable. Sudden price shocks have significant macro-economic impacts with cost consequences that are measured as a percentage of lost World GDP instead of additional cents per kWh electricity produced. Strategic energy dependence is another aspect of future energy systems. All developed countries need to reduce their dependence on fossil fuels imported from a limited set of countries and renewable energy can contribute to this goal. Renewable energy becomes an instrument to reduce energy system risks. Several European governments formulated ambitious targets for the share of renewable energy in total energy use by the year 2050 and we expect that more countries will follow this example. Our portfolio analysis showed that PV, next to wind energy, offers the ability to reduce the risk from fossil-fuel dependence while the cost consequences of the resulting energy system transformation are modest. Not investing in PV is much riskier than promoting the diffusion of PV.

In the young but strongly growing global PV market, the most important Japanese and European companies have ambitious expansion plans. Further increases of cumulative production will lower future prices and this process can have problematic consequences for the least efficient producers. A market shake-out in 2005 or 2006 would be no surprise.

In their expansion plans, most companies refer to the booming German market. This illustrates the fragility of the current PV market. The reverse image of this situation of dependence is that the European PV market would really explode when a few other countries would follow Germany’s example. In Japan as well as Europe, there are currently no problems for doubling or even tripling PV production capacity. The Belgian case of Photovoltech illustrates that Belgian engineers and technicians have the skills to play a significant role in the global market. The global PV market is highly dynamic and flexible. The German company Q-Cells managed to build new plants in 6 to 8 months. PV installations have the advantage of offering flexibility to its buyers and apparently the same flexibility is found with respect to constructing new PV plants. These are all indicators that policymakers really can move this industry with targeted incentives. Europe has the technical skills, abilities and networks to dominate the PV market in the coming decade. But this will only happen when national programmes are launched to create the markets.

With respect to market creation, especially the German case illustrated that technological progress is only one side of the story: institutional change is at the heart of the policy process. Various policy fields ranging from R&D policy to educational priorities need to be aligned towards clear goals and persist during difficult periods. New firms need to find support in the existing institutional infrastructure and initial markets need to be created for a new technology. A new sector can only take-off when backed by a broad constituency.

In addition to the advantages of PV with respect to the reduction of external effects and energy dependence risks, it is crucial that strategies to develop new climate friendly technologies such as PV are positioned in the current emphasis on cost-effective and short-term ‘hot air’ mitigation options in climate policy. But the period after 2012 will of equal, if not larger, importance than the current goal of climate policy. The focus on short-term options risks to neglect long-term necessities of which new technologies are ranked first. PV clearly plays a role in long-term climate policy but we should be aware that current institutions and 'soft' instruments such as low energy taxes will never trigger massive PV investments. On the contrary, the further and expanded use of current climate policy instruments – environmental taxes as well as emissions trading and green certificates- even risk to detract investment funds from radically new renewable technologies to the most mature renewable technologies such as wind energy. Therefore, an ambitious technological policy is needed in climate mitigation strategies.

We conclude with an overview of possible policy options to accelerate the diffusion of residential PV. Most countries will favour a mixture of instruments and strategies but our analysis suggests that especially technical regulation in the form of building standards can yield most advantages at a very low cost. Compared to annual price increases of real estate in the residential sector, mandatory investments in PV-systems only marginally impact the price of apartments in PV-equipped buildings. Our examples illustrate that the technical standard generates a price increase between 1 and 2% for each individual buyer of an apartment in the building with a PV-system on the roof. The mandatory standard forces all involved parties – project developers, architects, electricians, roofers, sales people, etc – to establish more or less stable relations to lower the time cost of integrating PV installations in the total project. In the literature on technological take-off, this formation of institutions is essential. The standard simply makes it impossible for architects to neglect the integration of PV installations.

In the initial phase of implementation, this mandatory standard will confront project developers with several logistic and practical problems. This will imply frequent interactions with PV suppliers. Therefore, we can assume that this standard will provide a boost to especially Belgian PV firms since these are best aware of local construction practices and are best located to provide flexible solution to urgent construction problems.

The mandatory standard can create a very promising initial market. The potential impact of the standard is high. Once 500 projects installed each 10 kWp, a generating capacity of 5MWp is created. If we –optimistically- assume that each year 500 projects will be completed, after 10 years a minimal Belgian PV-capacity of 50 MWp is realized. As a matter of comparison, the largest European PV company – Shell Solar- produced in 2003 modules with total capacity of 52 MW.

Furthermore, we need to stress that this type of technical standards has no cost for government budgets. To the contrary, the measure will generate incomes. Finally, a more symbolic advantage of the measure would consists of the additional exposure to Belgian ambitions to contribute to the gradual transition to a low-carbon economy. We conclude that there are no reasons for not supporting the take-off of PV industries in Belgium or other European countries.

E. Appendix : Competition among renewable energy technologies: PV and Biomass

From the preceding overview, we concluded that photovoltaics are assumed to play a significant role in the future mix of energy technologies. In the portfolio analysis, PV has been introduced into a model consisting of gas, coal, nuclear and wind technology. This analysis illustrated the long-term benefits of PV in the energy technology mix. There are however other renewable energy technologies that hopefully also will gain importance in the coming decades. In this section, we analyse the possible competition between two relatively 'new' renewable energy technologies[26] – PV and biomass- based on the portfolio model that has been presented in section 4 of part A. We wonder whether investments in one of these renewable energy technologies has the potential of crowding out the other one, i.e. will support for biomass energy limit the market potential of PV and vice versa?
After a brief overview on the potential of biomass energy, a portfolio framework for 2025 will be used to illustrate the expected trade-offs between PV and biomass for policymakers.

1. Bioenergy and the potential of biomass

Global bioenergy consumption and production potentials are difficult to quantify. Most estimates assume that currently around 12-14% of the world's energy is provided by biomass energy. In developing countries, the share of biomass energy is estimated at 34% but these numbers must be treated with great caution (Obersteiner *et.al*., 2002). The WEA 2004 report distinguishes between 'traditional' biomass (9.3% of world primary energy production) and 'modern' biomass (1.4 % of world primary energy production). Although speculative, these estimates show that biomass energy is currently much more important that for instance wind energy, responsible for less than 0.7 % of world primary energy production (WEA, 2004).
The theoretical potential of biomass energy is much larger than the actual base but this will require the implementation of pro-active changes in land use policies. At the global level, a comprehensive policy to stimulate changes in land use will be very

[26] '*New*' refers to the limited market diffusion of biomass and PV in the European energy technology mix. Biomass energy is the first energy technology ever used but modern biomass energy technology are only widely used in a few developed countries.

labour as well as skill intensive. Especially in developing countries, thousands of new biomass projects can contribute to lowering future greenhouse gas emissions but then thousands of local communities need to be trained, motivated and financed to participate. Additional efforts will be needed in terms of monitoring, the selection of appropriate technologies, logistics and project sustainability. Obviously, this is an enormous challenge.

In developed countries, the use of biomass in conventional boilers for district heating, electricity production and cogeneration (CHP) is of great importance in the primary energy consumption in the Nordic countries (Denmark, Sweden, Finland) and Austria. Biomass for district heating and CHP is also well established in Denmark and Germany.

Two basic approaches to biomass conversion for electricity and heat can be used:

1. direct combustion technologies : from simple biomass burning for direct heat in a domestic boiler, stove or open fire, to large scale utilisation of biomass products such as wood chips for electricity generation, district heating and cogeneration (CHP);
2. gasification of biomass products to provide gaseous fuesl for a wide range of uses including large and small scale CHP; as a feedstock for fuel cells, and for heating systems. An emerging application is biomass integrated combined cycle electricity generation and CHP or BIGCC.

Also in developed countries it is possible to increase the use of biomass energy. Depending on the climate of each country, fast rotating trees such a willow or various types of switchgrasses can provide biomass inputs. However, especially in countries with a high population density and a very intensive agricultural sector, the opportunity cost of investing in expanded biomass harvesting can become prohibitive. A larger area used for biomass cropping implies less opportunities for other activities. Biomass inputs can also be imported but then the cost of the inputs will increase. Furthermore, transportation that is based on fossil fuels will reduce the carbon neutrality of biomass energy.

2. the cost of biomass electricity

With respect to the cost of electricity from biomass combustion technologies, estimates depend on the many possible technological configurations as well as on the mix of inputs. For an overview of biomass projects in Belgium we refer to the recent report by VITO for ANRE. However, most cost estimates for conventional combustion technologies without cogeneration range between 0.05 and 0.07 Euro per kWh (WEA, 2004 ; Oregon Department of Energy, 2004). These cost figures include a capital cost around 0.04 Euro per kWh, an operational cost and the cost of the inputs. Fuel transportation, storage and handling costs are a significant part of the costs of biomass energy production[27]. A complete overview on the cost per kWh for all Belgian biomass projects is not available but for an optimally integrated conventional installation on woodchips the electricity cost is estimated at 0.031 Euro per kWh (Vito, 2004). As always, this estimate depends on many variable such as the size of the plant and the rate of utilisation. Several authors argue that combustion plants should be as flexible as possible. One strategy to deal with fuel supply uncertainty is to design the facility to handle multiple biomass fuels types. The learning rate for electricity production from conventional biomass is now rather low since the combustion technology is rather mature.

3. Biomass and PV in the portfolio model

Assuming that the current (2005) electricity cost of the average conventional biomass plant is 5 Eurocent/kWh, we obtain a portfolio return of 0.2 kWh per cent invested. Conventional biomass clearly outperforms PV with a return of 0.125 kWh/cent. When climate policy is reduced to short-term mitigation targets – as it seems to be up to 2012- policymakers could prefer to invest in biomass projects and not in PV projects. In terms of cost-effectiveness, biomass would rank behind wind energy but clearly before PV. When resources for renewable energy projects are limited – a very realistic hypothesis- the focus on biomass endangers the long-term evolution of the expected learning effects of PV. Lower investments in PV risk to add more years to the time needed to achieve competitive PV projects. From this perspective, policymakers

[27] In some cases, the inputs can be obtained for free. Even the transportation cost of bringing organic waste to the combustion facility is then covered by the waste producer.

should be careful not to crowd out investments in PV by allocating the bulk of support funds to other than PV projects.

Over a longer period, we need to consider other aspects as well. In the 2025 B scenario, it is assumed that the price of PV electricity will fall until PV generates a return of 0.3 kWh per Eurocent (see Table II). By 2025, electricity from biomass plants can also become cheaper but here several effects interact. Based on the learning effects for the combustion technology, the price in Eurocent per kWh can be reduced but an increased use of biomass in the electricity portfolio will be restricted by the capacity to produce renewable biomass inputs. We should therefore assume that policies to support biomass energy in several European countries can lead to upward price movements for the mix of biomass inputs. Because of the nature of the transportation processes in 2025, it is quite reasonable to assume that biomass input prices – when delivered at the combustion unit- are slightly but positively correlated to fossil fuel prices. Higher petrol price will make the transportation of biomass inputs more expensive. In addition to increasing transportation costs, the rising prices for biomass inputs – due to rising marginal opportunity costs of land use- can increase this price correlation to relatively high levels. Both scenarios – low and high correlation levels- limit the attractiveness of biomass in a portfolio that balances return as well as portfolio risk. Biomass can be a sustainable energy technology but its capacity to reduce input price risk is clearly less attractive when compared to wind energy and PV. Of course, biomass energy can reduce our energy dependence on fossil fuels imported from the Middle East. The benefits from diversification should be clearly distinguished from the pure input price risk.

For the portfolio model, we assume that the price of biomass electricity will in 2025 fall to 0.04 Euro per kWh, what leads to a return of 0.25 kWh per Eurocent invested. Solely based on price comparisons, PV is a more attractive option in 2025. However, this price comparison still neglects the contribution of the renewable energy technology to portfolio risk reduction. Starting from the initial 2025 B model with parameter values in Table II, we added biomass to the 2025 portfolio with a return of 0.25 kWh per Eurocent and an input price correlation of 0.05 with coal and gas prices. The correlation between biomass inputs and uranium was set a 0. The standard deviation of the biomass input prices was set at half of the level of gas price changes (i.e. at 0.05). These assumption are crude since there simply is not standard biomass input. National differences can be significant but this portfolio mainly represents the average European situation.

To compare the contribution of biomass to that of PV, we first assumed that the share of the other energy technologies in the European mix was restricted as follows:

- the share of gas ranges between 40 and 60%;
- the share of coal ranges between 0 and 20%;
- the share of nuclear ranges between 10 and 30%, and ;
- the share of wind ranges between 10 and 30%.

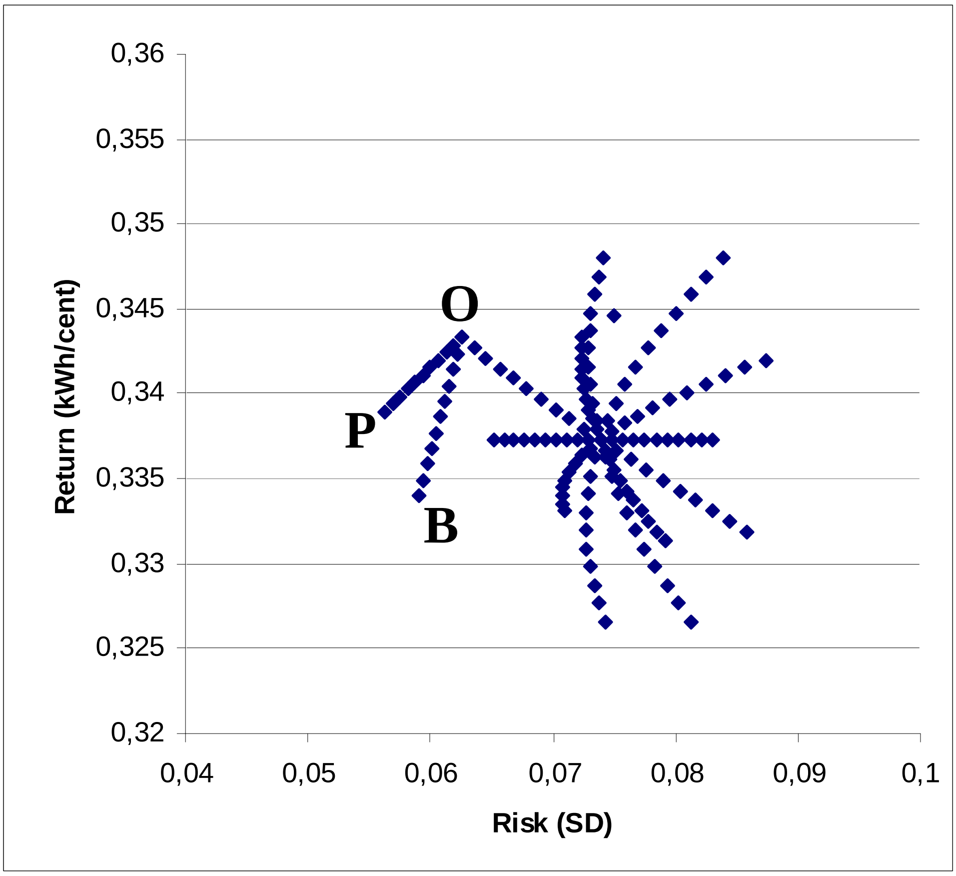
The portfolio results of all these combinations are presented in Figure V. The best option in this simplified model 2025 B is found in point O: 50% gas, 10% coal, 10% nuclear and 30% wind. This combination results in a return of 0.3433 and a risk of 0.0625 (SD). In a next simulation we add biomass to combination O. The share of biomass evolves from 1% to 10% and the other technologies in combination O are all reduced by the same percentage[28].

The results are presented by the combinations from O to B in Figure V. The same exercise is then repeated for the integration of PV in the technology mix of combination O. When the share of PV is increased from 1 to 10%, we obtain the portfolio combinations between O and B in Figure V.

Figure V shows that a 10% share of PV leads to a return of 0.3389 and a risk of 0.0562, while a 10% of biomass results in a return of 0.3339 and a risk of 0.0590. Based on this simplified analysis, biomass energy implies a lower return at a high portfolio risk. From this perspective, the long-term potential of PV is clearly preferable over that of biomass.

Figure V – Portfolio analysis for PV and biomass in 2025

[28] When the share of biomass is 5%, the share of gas is then 50*(1-0.05).



4. Policy recommendations

These findings should not interpreted as an argumentation against biomass in a diversified energy technology mix. The main conclusion is that PV can offer a very valuable contribution to climate policy as well as energy security policy, especially when the technology is shielded from competition for at least one decade. Without support mechanisms, a more mature renewable technology such as biomass looks more attractive in the short-run. Shifting support mechanisms from PV to biomass would benefit biomass production but endangers the important potential of PV in the long run (here up to 2025). Therefore, the main conclusion from this analysis is that PV deserves specific technology and/or market creation support, even when other renewable technologies look superior in the short-run. In a purely competitive markets, PV has no ability to grow strongly and even biomass risks to become outcompeted by wind projects.

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