Application of portfolio analysis to the Dutch generating mix

Reference case and two renewables cases: year 2030 - SE and GE scenario

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Abstract

This report presents results of an application of Markowitz Portfolio Theory (MPT) to the future portfolio of electricity generating technologies in the Netherlands in year 2030. Projections are made based on two specific scenarios constructed by CPB, i.e. 'Strong Europe (SE)' and 'Global Economy (GE)'. This study zooms in on the electricity cost risk dimension of the Dutch portfolio of generating technologies.

Major results of this study are:

- In both scenarios, the base variant is not very efficient. Graphical analysis suggests that diversification may yield up to 20% risk reduction at no extra cost;
- Promotion of renewable energy can greatly decrease the portfolio risk. Defining mixes without renewables results in significantly riskier mixes with relatively small impact on portfolio costs.
- Because of its relative low risk and high potential, large-scale implementation of offshore wind can reduce cost risk of the Dutch generating portfolio while only in the GE scenario a (small) upward effect on the projected Dutch electricity cost in year 2030 is foreseen. In a SE world large-scale implementation of offshore wind is projected to have a downward effect on Dutch electricity prices by the year 2030.

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Summary

This study presents results of an application of Markowitz Portfolio Theory (MPT) to the future portfolio of electricity generating technologies in the Netherlands in year 2030 under two specific scenarios. The scenarios and underlying assumptions, i.e. ‘Strong Europe (SE)’ and ‘Global Economy (GE)’ have been adopted from the CPB. This enabled us to make the underlying assumptions broadly comparable to a recent CPB-ECN study on social cost-benefit analysis of large-scale implementation of offshore wind (Verrips et al., 2005).

This report sets out to provide complementary insights, zooming in on the cost risk dimension of the future Dutch portfolio of generating technologies. Moreover, it presents some recent advances in the still fledgling field of MPT applications to portfolios of electricity generating technologies. The MPT analysis focuses on the role of renewables-based generating technologies within the Dutch generating mix in 2030. For each of the two aforementioned CPB scenarios, three policy variants are considered. One is a reference variant assuming continuation of current policies regarding renewables promotion, whilst the other two are alternative policy variants. In line with the alternative policy options that seem most appealing for the near future, one policy variant emphasizes large-scale implementation of offshore wind and the other assumes a broad-based promotion of renewable generation technologies. To this end, we determine a set of efficient portfolios. These portfolios are defined to be those for which the expected portfolio cost of electricity (COE, in €/MWh) cannot be reduced without increasing the expected portfolio cost volatility (standard deviation of COE, also expressed in €/MWh).

Results suggest that, in both scenarios, policy variants with high promotion of renewable energy generation are attractive from a socio-economic perspective. Portfolio (cost) risk can be reduced significantly (i.e. by up to 20%) through diversification with a key role for renewables. The characteristic of renewables-based technology to reduce portfolio risk is rather robust. This is an important additional result to conventional stand-alone cost-benefit analysis of specific generating technologies.

Under the GE scenario this reduction can be realized at a relatively modest additional cost. Under the SE scenario the alternative (high renewables) policy variants could even result in a decrease in generating costs. Results suggest that the cost-risk performances of the offshore wind policy variant and the broad-based renewables variant are comparable under SE, whilst under the GE scenario the broad-based renewables variant, notably biomass, comes out slightly better.

Sensitivity analysis shows that *increasing offshore wind* can significantly reduce cost risk for the total Dutch generating portfolio. A simulation of stepwise realization of offshore wind up to 6000 MW shows that every additional MW has roughly the same risk reducing potential (up to 6000 MW).

Furthermore, *the future carbon price trajectory* is shown to have a major impact on the socio-economic attractiveness of increased penetration of renewables in power generation. A higher carbon (CO_2) price dramatically improves the market position of renewables. Moreover, the socio-economic attractiveness of renewables-based generation technologies is highly contingent on future prices of gas and to a lesser extent to coal.

The economics of renewables-based generating technologies are quite sensitive to the evolution of *the gas price*. In this respect, it is remarked that both the GE and the SE scenario assume a rather moderate gas price evolution compared to average expert views.

Since biomass is only considered in co-firing and the share is limited, variations in *the biomass price* have minor impact on portfolio cost and risk. With an increasing biomass price, the mix shifts towards a larger share of coal.

This study presents some adjustments - proposed and implemented by the authors - to recent MPT analysis of generating mix portfolios:
1. Introduction of a notion of the efficient frontier based on cost.
2. Use of energy based instead of generating capacity based portfolios.
3. Expression of risk in terms of costs instead of a percentage rate.
4. Consistent framework for determination of risk associated with generating costs for individual options.
5. Incremental technology deployment analysis.

At the same time, this report identifies some major limitations and remaining weaknesses of the MPT applications to generating mix portfolios in want of further improvement.

Distinctive features of the MPT approach introduced in this report are that consistent *quantitative* allowance is made for:
- *Technology cost risk* associated with distinct technology-specific cost of electricity.
- The - potentially large - societal benefits associated with the risk-mitigating *portfolio effect*. For example the cost risk of gas-based generating technologies is far from perfectly correlated with the cost risk of renewables-based technologies. With prevailing short-termish optimisation behaviour of key stakeholder categories into the direction of moderate capital-intensity gas-based CCGT technology it would appear highly desirable to include the portfolio effect into a *quantitative* framework to analyse the generating mix *from a societal perspective*.
- *Supply-side volume risk*. Supply-side volume risk factors include uncertainty regarding efficiency-enhancing technological development and the supply variability relating to so-called intermittent renewable resources (wind, solar), risks regarding physical fuel input availability (fossil fuel, biomass energy feedstock) and to unscheduled outages.

Further application of the MPT methodology for assessment of generating mix portfolios for policy design purposes merits serious consideration. Unlike conventional approaches (conventional power system expansion optimisation analysis; cost-benefit analysis), by including portfolio COE (cost of electricity) risk this approach is capable of integrating the three key objectives of energy policy - competitive energy prices, energy supply security and mitigation of adverse environmental impact - in an integrated *quantitative* framework. This is a key distinctive feature of the MPT approach. MPT can be applied to monitor the current and projected evolution of a country's electricity mix from a perspective of limiting the risk that an undesirably high level of portfolio cost would occur in a certain future year. This can be done through MPT-based Value at Risk analysis. Such analysis results in recommendations of how to properly rebalance electricity mix portfolios that have a higher risk than the desired risk, e.g. 2.5 %, that the portfolio COE level will exceed a pre-set norm level. In such analysis this COE upper bound would serve as a long-term electricity supply security norm, to be proposed in close consultation with policymakers.

1. Introduction

The Ministry of Economic Affairs (EZ) is considering the socio-economic impact of its renewables stimulation targets and policies over the period up to year 2020. To that effect CPB, in association with ECN, has performed a social cost-benefit analysis of possible large-scale implementation of wind offshore in the Dutch continental shelf (Verrips et al., 2005). On the side of this exercise, EZ has requested ECN to conduct portfolio analysis of projected Dutch generating mixes in year *2030* under the reference case and the two alternative renewables cases under the SE scenario.

Financial portfolio analysis, based on Markowitz Portfolio Theory (MPT), builds on the premise that a portfolio of well-chosen assets has reduced risk characteristics when no perfect mutual correlation between the return on each of pair of assets exist. In a similar line of argument, portfolio (cost) risk may be reduced in a portfolio of well-chosen generating technology options as a result of less than perfect correlations between their cost characteristics.

Earlier studies, such as Awerbuch (2000), Awerbuch and Berger (2003) and Berger (2003) suggest that introducing renewables in the generating portfolio may significantly affect overall 'HPR (holding period return)' risk. This study takes the approach one step further by proposing some adjustments in the theoretical framework, among others the introduction of the concept of 'cost risk' replacing the expected returns concept applied in the studies referred to above.

In this study, the MPT approach is applied to future Dutch generating mixes for the year 2030, evaluating risk against *two CPB scenarios*, i.e. Strong Europe (SE) and Global Economy (GE). For each scenario, *three policy variants* are evaluated: the base- or 'zero' variant, an alternative variant articulating offshore wind power and another alternative broad-based renewables variant. Furthermore, a sensitivity analysis of some specific external effects to the risk and efficiency is performed, focusing on changes in the price of natural gas, the CO_2 price, the biomass price and changes in offshore wind targets/constraints.

This report is organised as follows. Chapter 2 provides a short introduction to portfolio analysis as applied to electricity generating mixes and discusses some improvements made to the theoretical framework. Chapter 3 presents the main portfolio analysis to the Dutch 2030 generating mix and policy variants. Chapter 4 describes and analyses the sensitivity of the outcomes to variations in CO_2 prices, gas prices, biomass prices and offshore wind constraints. Finally, Chapter 5 winds up this report with main conclusions.

2. Portfolio analysis for the electricity generating mix

2.1 Introduction

In the remainder of this report, the portfolio analysis approach for asset investments introduced by Harry Markowitz in the early 1950s (Markowitz, 1952) will be referred to as Markowitz Portfolio Theory (MPT). This reference has the same acronym as the commonly used label: 'Modern' Portfolio Theory. Its original and still most important application is to determine optimal portfolios of financial assets (Fabozzi et al., 2002). In the literature, MPT is also known as Mean-Variance Portfolio Optimisation. In its initial application, periodic returns for portfolios of financial assets are optimised for a range of given risk levels. In doing so, the variance or rather - equivalently - the standard deviation of periodic portfolio returns is taken as risk measure. Alternatively, risk levels are optimised for a range of given periodic return levels. Thus, it allows for the optimal return given the risk level and vice versa.

Markowitz portfolio theory (MPT) proposes how rational investors will use diversification to optimise their portfolios. An investor can reduce portfolio risk simply by holding assets, the returns of which show diverging patterns of co-variation. In other words, investors can reduce their exposure to individual asset risk by holding a diversified portfolio of assets. *If the returns on any two assets in the portfolio have a correlation of less than 1, the portfolio volatility*[1] *will be less than the weighted average of the volatilities of the portfolio's individual assets.*

Applications of MPT to be set out hereafter relate to the power generation sector in a region or a country. These applications enable policy makers and electricity supply system analysts to consider the mix of power generation technologies by way of performing portfolio analysis consistent with MPT. A key distinctive feature of the portfolio analysis approach, compared to conventional least-cost power system expansion planning, is that it allows for the incorporation of risks surrounding projections of the unit energy costs (MWh costs) of alternative electricity mix portfolios. A major electricity cost category is fuel cost. In the electricity supply systems of many countries fossil-fuel-based generating technologies - notably natural gas, coal, and oil - are quite dominant. Serious risk to supply security may be an upshot of this dependence.

MPT analysis for power generating technologies provides a consistent framework to gain better insight into the portfolio (cost) risk, associated with alternative technology deployment portfolios. The MPT analysis framework, to be further elaborated hereafter, is patterned upon a set of premises on technology unit costs, their mutual co-variation relationships, and the risks associated with these costs.

It is emphasised that this report highlights the *medium to long-term societal* perspective.[2] The key risk associated with long-term electricity supply is cost competitiveness of the electricity generating mix of a country (say, the Netherlands) or a region (say, the European Union). For generating portfolios from a private perspective and a *short-term* societal perspective, demand-side volume risk or rather price risk is also of key concern. However, *in the long run* short-term business cycles characterised by periodic boom-and-bust features in the electricity supply industry, capacity shortages and redundancies tend to show long-term mean reversal towards a reserve margin on the order of 15-20%. From a long-term societal perspective the key concern is

1 As indicated by the standard deviation of periodic holding returns.
2 For portfolio analysis over (ultra-)long-term time horizons, alternatively, reliance might be sought to the non-probabilistic diversity approach pioneered by Andrew Stirling. See: Stirling (1994; 1998), Jansen *et al.* (2004), Awerbuch *et al.* (2006).

how to meet the evolving future level of electricity demand at lowest cost given pre-set acceptable cost risk and respecting pre-set environmental constraints.[3]

Distinctive features of the MPT approach, notably the variant introduced in this report, are among others that it makes consistent *quantitative* allowance for:

- Risk associated with projected distinct technology-specific cost of electricity.
- The - potentially large - societal benefits associated with the risk-mitigating *portfolio effect*, as for example the cost risk of gas-based generating technologies is far from perfectly correlated with the cost risk of renewables-based technologies. With prevailing short-termish optimisation behaviour of key stakeholder categories into the direction of moderate capital-intensity CCGT technology it would appear highly desirable to include the portfolio effect into a *quantitative* framework to analyse the generating mix from the societal perspective.
- Volumetric risks associated with supply-side factors.[4] Such factors include uncertainty regarding efficiency-enhancing technological development and the supply variability relating to so-called intermittent renewable resources (wind, solar), risks regarding physical fuel input availability (fossil fuel, biomass energy feedstock) and to unscheduled outages.[5] If policy makers wish to additionally include demand uncertainty into the analysis, this can be addressed by introducing different scenarios.

By including portfolio (cost of electricity) risk, the MPT approach set out in this report enables policy makers to integrate the '*trias energetica*' (competitive energy prices, energy supply security, mitigation of adverse environmental impacts) in a quantitative framework. The proposed approach enables policy makers to monitor electricity cost risk developments using an energy supply security norm as yardstick, i.e. a pre-set upper bound to the real COE. This will be further elaborated in this chapter.

MPT analysis can reveal the potential role for renewables-based technologies in mitigating the impact of long-term energy supply security risk to a certain national or regional electricity supply system. Application of MPT to electricity generation shows that deployment of renewables-based generating technologies can be instrumental in mitigating this risk.

The application of MPT to electricity generating portfolios is still under development. In this chapter a number of improvements for the theoretical framework are presented. Without loss of continuity, the general reader may wish to jump to Section 2.5.

2.2 Applications of MPT to financial portfolios

The main area of application for MPT analysis is the selection of efficient portfolios of financial assets. These portfolios are optimal with regard to the trade-off between periodic portfolio return and its associated risk. Given the level of (expected) risk of a certain *efficient portfolio* selected from a certain universe of financial assets, no portfolio with another asset allocation can be found that yields a higher (expected) return without increasing (expected) portfolio return risk.

Expected portfolio return in MPT applications to financial markets is the expected *holding period return* (HPR). This is total return per period as a proportion of the portfolio value at the be-

3 Should policy makers wish to see the impact of alternative long-term demand evolutions on the composition of efficient portfolios of a certain cost or risk level, this issue can be addressed either in the definition of scenarios or by way of sensitivity analysis.

4 Distinct from the methodology developed by Awerbuch and Berger (2003), the approach proposed in this report does allow for supply-side volumetric risk.

5 In principle, the MPT methodology developed in this report can be adjusted to make it applicable as a tool for electricity supply system expansion analysis from the perspective of large private stakeholders. An adjusted MPT model covering the utility perspective would have to encompass electricity price risk. See e.g. Roques *et al.* (2005).

ginning of the period.[6] For the aforementioned applications the standard deviation (or, equivalently, its square: the variance) is widely considered an adequate risk measure of the HPR.[7]

Major outputs of MPT analyses on portfolios of a set of risky assets (not comprising a risk free asset) include:

1. A model calculating portfolio return and risk combinations for varying asset allocations along with the set of minimum risk portfolios at varying returns. Asset allocations are denoted by holding weights, summing up to one.
2. A graph of the '*minimum variance frontier'*. This graph - with risk values on the X-axis and portfolio expected returns on the Y-axis - depicts a set of points, each of which indicates a given portfolio expected return and the minimum expected standard deviation (c.q. the minimum variance, being the square of the standard deviation) that can be attained for the indicated portfolio expected return. The part of the frontier that lies above the global minimum-variance portfolio is called the *efficient frontier*.
3. A diagram showing *the composition of the efficient frontier* for a wide range of risk values (e.g. Fabozzi *et al*. (2002:11, exhibit 11)).

These outputs can be generated, based on a simple non-linear optimisation model. See Annex D.

2.3 Applications of MPT to electricity mix portfolios

More recently, forward looking mean-variance portfolio analysis has also been used to optimize cost-risk for real-asset portfolios related to electricity generation and energy in general. The to our knowledge first application to the electricity sector is an article by Bar-Lev and Katz, published in 1976 in the prominent Journal of Finance[8]. Bar-Lev and Katz apply a portfolio approach to fossil fuel procurement in the U.S. electric utility industry. Their article focuses on the cost of coal, oil and gas input. To our knowledge, this article did not trigger follow-up research.

Initially ignorant of the Bar-Lev and Katz article, Shimon Awerbuch deserves due credit for putting these kind of applications of Markowitz portfolio approach on the research agenda in the 1990s. In his first articles on the portfolio of generating assets, Awerbuch formulated the problem as minimizing fossil fuel 'reward' (i.e. cost effectiveness) risk at given levels of fossil fuel 'reward'.[9] Point of departure for using Markowitz portfolio analysis is that future outcomes of the argument of the objective function (here: fossil fuel 'reward') can be expressed in terms of risk.[10] Awerbuch's initial portfolio model included typically one coal-based, one gas-based and one-renewables (wind or PV) based generating technology (e.g. Awerbuch, 2000). Alluding to the HPR concept for financial portfolio applications of MPT, Awerbuch presented risk as a percentage rate, whereas he expressed 'returns' in terms of energy (kWh) per monetary unit (US$ct). Awerbuch's approach adds a quite significant dimension to the interpretation of technology-specific unit cost and overall system unit cost of electricity, i.e. cost risk. This important dimension of cost is grossly overlooked in standard levelised cost of electricity approaches and standard electricity system optimisation modelling. Awerbuch's approach enables analysts and policy makers to gain valuable insights into issues such as mitigation of the impact of price volatility of fossil fuels upon the future electricity mix of a country or region. The usefulness of the MPT approach to analyse generating portfolios is recently gaining recognition among re-

6 To put it more specific in the context of financial assets, it is the capital gain income plus dividend income over the period considered, say a year, per US$ (€) invested in the financial asset. C.f.: Bodie *et al*., p. 136.

7 Initially Markowitz used variance as risk measure (Markowitz, 1952). The Markowitz portfolio optimisation approach is still often referred to as Mean-Variance (M-V) optimisation approach, although standard deviation has been replacing variance as the risk measure commonly used in evolving variants since several decades.

8 Markowitz' 1952 landmark article was also published in the Journal of Finance.

9 Fossil fuel 'reward' is defined as kWh/US$ct, i.e. the inverse of fossil fuel cost per unit of electricity output, expressed in holding period 'returns'.

10 Stirling (1994) associates risk with a measure where 'a probability density function may meaningfully be applied for a range of possible outcomes'.

puted power sector researchers.[11] We revert to recent versions of Awerbuch's MPT modelling approach in more detail in the next section.

Another application of MPT is the analysis of the energy mix portfolio of a country or region. In principle, such applications may range from a 'simple' three-fuel (coal, natural gas, crude oil) model to a quite complicated MPT model with reference energy sub-modules for electricity end-uses, heat end-uses, and liquid fuel end-uses (mainly for transportation). To our knowledge, the latter ("complicated" MPT energy model) still needs to be developed. An interesting example of the former ("simple" MPT energy model) is a paper by Brett Humphreys and Katherine McClain (1998) on cushioning the negative impact of price volatility of fossil fuels on the U.S. economy by selection of appropriate efficient energy mix portfolios. This article is interesting for several reasons, including the use of GARCH (generalized autoregressive conditional heteroskedasticity) models to project time-varying variances and co-variances.

2.4 Theoretical refinements

This study adopts a number of adjustments and additions with respect to the MPT framework developed by Awerbuch (2000), Berger(2003) and Awerbuch and Berger (2003), viz.:

1. Introduction of a notion of the efficient frontier based on cost risk instead of 'return' risk.
2. Use of energy based instead of generating capacity based portfolios.
3. Expression of risk in terms of costs instead of a percentage rate.
4. Consistent determination of risk associated with generating costs.
5. Incremental technology deployment analysis.

The authors have initially proposed these refinements. Adjustments 1, 2, and 5 have been accepted and adopted by Shimon Awerbuch in collaboration projects with ECN and in Awerbuch (2005), while adjustments 3 and 4 have not been presented earlier.

A brief explanation of each of these refinements follows hereafter.[12]

2.4.1 From a risk-return to a risk-cost efficient frontier

The authors have proposed and implemented in an AIMMS[13] model a *risk-cost efficient frontier*. This type of efficient frontier shows a graph of risk (expressed in €/MWh) and cost of electricity (COE, expressed in €/MWh) for all efficient portfolios. A portfolio is efficient when a marginal increment in the output of any generation technology does not reduce portfolio cost without increasing risk (or does not reduce portfolio risk without increasing cost). Underlying efficient portfolios are energy-based (i.e. based on shares of constituent electricity generating technologies in terms of electricity generation, e.g. in GWh or TWh, instead of MW capacity). We revert to the 'portfolio risk' concept proposed in this report in Sub-section 2.4.3 below.

For various reasons the authors proposed the transformations from a risk-return to a risk-cost efficient frontier for electricity mix applications of MPT, viz.:

- 'Return' has quite a different prevailing (financial or physical 'profit') connotation than just the reciprocal value of cost per unit of energy.
- Unlike propositions made by Berger (2003) and Awerbuch and Berger (2003) the reciprocal of portfolio cost is *not* the same as portfolio return, if the latter is properly defined (See proof in Annex H).

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11 See e.g. the state-of-the-art report: Roques *et al.* (2005).

12 For more details the reader is referred to Annex D.

13 AIMMS is a dedicated optimisation modelling framework.

- Last but not least, the conversion from portfolio cost to a parameter defined as its reciprocal (dubbed 'portfolio return') makes the link to portfolio risk problematic. At any rate the latter cannot be expressed in the same dimensions as the reciprocal parameter of COE.

2.4.2 Using energy based portfolios

This study uses *energy-based portfolios*. Capacity-based electricity portfolios are intuitively attractive, as they are more readily associated with portfolio 'assets' in a similar vein as financial portfolios than is the case with energy-based portfolios. However, using capacity-based portfolios as efficient portfolios underlying each point of the efficient frontier is rather unrealistic. Because of diverging capacity factors for distinct constituting generating technologies, total capacity in terms of MW or GW installed typically tends to vary among various efficient portfolios that have to meet a given one-period electricity demand. Evidently, *derived* capacity-based efficient portfolios can be determined, based on the energy-based ones underlying efficient frontiers of generating technology deployment portfolios *in an additional computational operation*.

2.4.3 Determining portfolio risk in terms of cost risk

Efficient frontiers resulting from applying MPT to portfolios of financial assets depicts in a forward looking way a set of points, each of which corresponding to a particular efficient portfolio. Such an efficient frontier representation brings out two dimensions of underlying efficient portfolios: *the projected 'portfolio return' in percentage terms per period* (y-axis co-ordinate) and *'portfolio risk' (x-axis co-ordinate), i.e. the projected standard deviation of 'portfolio return', both expressed in the same dimension (% per period)*. Underlying efficient portfolios are composed of a certain efficient, linear combination of individual financial assets from a certain 'asset universe', with their respective shares in the projected portfolio value as weights. The essential feature of an efficient portfolio is that its (projected) portfolio return cannot be improved without at the same time higher portfolio risk exposure. *Note that the aforementioned risk concept, as brought out by efficient frontiers of financial portfolios, is quite transparent.*

From a societal point of view we consider the crucial question, *which portfolios can yield the lowest expected energy costs at given, acceptable levels of expected risk*. To answer this question we set out to find ways for constructing an efficient frontier, showing for the set of efficient portfolios the relationship between the expected portfolio COE (cost of electricity) - stated briefly: *portfolio cost* - and the expected portfolio COE risk, i.e. *portfolio risk*. Values of portfolio risk should have a transparent interpretation so as to enable the projection of confidence intervals of portfolio cost. To achieve this, we have deduced the details to pursue the following 3-staged procedure.

1. For each cost component considered making up the COE of a certain electricity generating technology, determine the expected value and the upper limit value of the two-sided 95% confidence interval.
2. For each generating technology considered, determine the expected value and the upper limit value of the two-sided 95% confidence interval based on results of step one.
3. Determine the efficient frontier, based on results of step two.

The technicalities and limitations surrounding the aforementioned procedure are set out in Annex D. *Whereas this procedure does not use a 'holding period return' notion, in its elaboration it is fully compatible with MPT applications to portfolios of financial assets.*

The portfolio risk indicator, emerging from this exercise can be interpreted in a transparent way: it simply is the (expected) standard deviation of portfolio cost. For a specific portfolio cost value it is approximately half the difference between the upper bound value of the projected portfolio cost interval and projected portfolio cost. Moreover, upper bounds of portfolio cost intervals can enable users, e.g. policy makers, to define their risk aversion preferences. For example, if a user wishes to accept, say, 90 €/MWh as a maximum COE with an overshoot risk of 2.5% (on average one case in the right-hand tail rejection area out of 40 cases), the portfolio with the lowest (expected) portfolio cost meeting this condition can be determined.

Hence by including portfolio (cost of electricity) risk, the MPT approach set out in this report enables policy makers to integrate the *trias energetica* (competitive energy prices, energy supply security, mitigation of adverse environmental impacts) in a quantitative framework. The proposed approach enables policy makers to monitor electricity cost risk developments using an energy supply security norm as yardstick, i.e. a pre-set upper bound to the real COE.

2.4.4 Definition of cost categories and determination of their risk

Unit technology costs are expressed in monetary terms per unit of electricity production. Hereafter all unit techology costs are expressed in *€ per MWh*. All costs are expressed *in real terms*, that is at the purchasing power of the monetary unit chosen at a certain date, e.g. in the present study mid-year 2003. Unit technology costs (UNCO) are broken down into the following cost categories:

- INCO investment cost
- FUEL fuel cost
- FIOM fixed O&M (operation and maintenance) cost
- VAOM variable O&M costs
- ENAD environmental adders

For a certain technology in a certain year the following holds:

UNCO = INCO + FUEL + FIOM + VAOM + ENAD

The distinct technology cost categories are described in some more detail in Appendix E. This annex also provides an overview of a new procedure applied to determine component-specific cost risk. A deductive 'proof' of the applied procedure has been obtained by conducting Monte Carlo analysis.

2.4.5 Incremental technology deployment analysis

Departing from a certain portfolio, it is interesting to know what would be the result of a marginal addition in the generation output of a certain technology upon portfolio risk and portfolio cost. A technology-specific Sharpe ratios can depict this, showing the tangent of the direction the portfolio under consideration would move to in the risk-cost plane by incremental use of a certain technology. See Annex D.

2.5 Presentation of results and potential use for policy design

In order to improve flexibility and overcome obstacles found in earlier spreadsheet-based models, ECN developed a new generic optimisation model for determining efficient frontiers. The new model uses the AIMMS dedicated mathematical modelling framework.

For the analysis of cost and risk for a portfolio of electricity generating options, the graphical presentation such as in shown in Figure 2.1 is used, combined with a table containing some key indicators for cost, risk and composition.

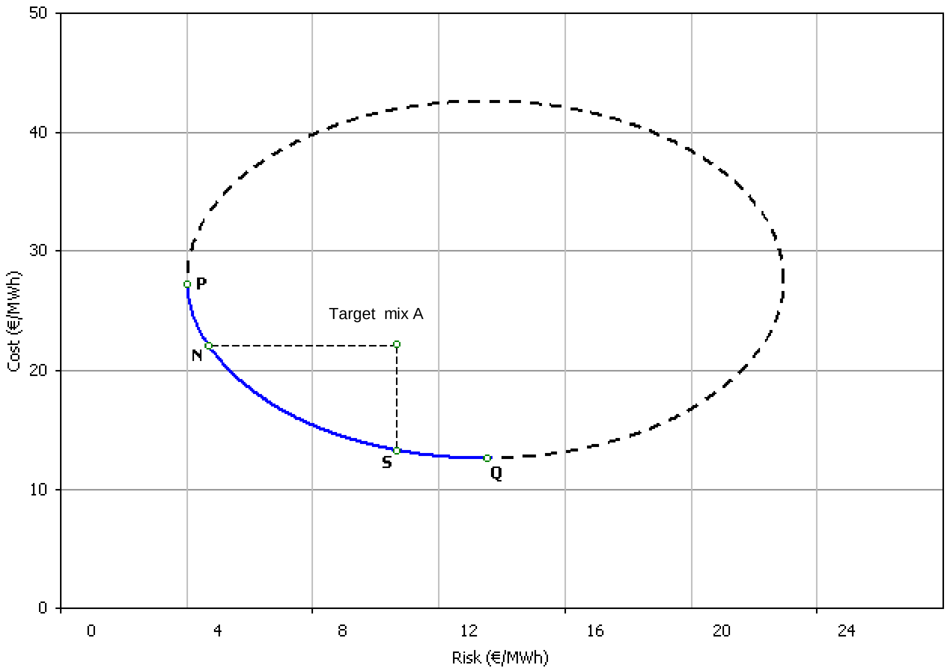

Figure 2.1 *Example: cost efficient frontier*

The dotted elliptic area indicates the range of feasible portfolios and the blue line indicates the cost efficient frontier, comprising all Pareto-efficient[14] combinations of risk and return. Note that the elliptic feasible area is formed under constraints on the different generating options. In an unconstrained world, the feasible area would resemble the well-known boomerang shape also found in financial applications.

Mix *Q* typically is the global minimum-cost-portfolio and mix *P* is the global minimum-risk-portfolio. Mix *A* represents a target mix for a certain target year. Generating mix *A* is clearly not efficient, since rearranging could either:

- reduce portfolio risk at the same portfolio cost (moving from A to point *N*), or
- reduce portfolio cost at the same risk (moving from point A to point *S*), or
- reduce both (all combinations between point A exclusive and arc NS inclusive, excluding those on lines AN and AS).

A fictitious example of characteristic points A, N, S, P, and Q is presented in Table 2.1.

[14] Pareto efficiency in this context indicates that no improvement in return can be attained without increasing risk and vice versa.

Table 2.1 *Example: aggregated results mix A*

		Mix P	Mix N - A	Mix A	Mix S - A	Mix Q
Portfolio cost	[€/MWh]	28.0	22.0	22.0	13.5	12.5
Portfolio risk σ	[€/MWh]	4.0	4.5	10.5	10.5	13.5
Upper bound at 2.5%	[€/MWh]	36.0	31.0	43.0	34.5	39.5
Gas CHP	[%]	25	30	35	25	25
Coal	[%]	25	25	40	30	25
Nuclear	[%]	5	5	5	5	5
Renewable wind	[%]	20	25	10	30	25
Renewable biomass	[%]	25	15	10	10	20

It was already stated that the above table denotes an illustrative example and is not based on real data. Assuming that the costs are distributed independently random, for each portfolio - characterised by its expected portfolio cost and portfolio risk - its maximum portfolio cost within a set probability can be calculated. This figure is presented as 'upper bound at 2.5%' and may be interpreted as the maximum cost that will occur with 97.5% certainty. Examples are given by the figures in the third row.

Policy makers may wish to set norms for maximum portfolio cost in certain milestone years. These norms can be taken as point of departure for monitoring the evolution of the actual electricity mix and actual technology costs. Based on updated technology costs (cost projections), the maximum portfolio cost in milestone years can be estimated (projected). 'Market failure' (e.g. the predilection of incumbent generators for CCGT with attendant high fuel cost risk) may render a country exposed to a supply security risk, considered unduly high by its policy makers. At least for the power sector, portfolio analysis can be used as a tool to monitor the level of energy supply security. Should the estimated portfolio cost in a milestone year exceed the pre-set norm, this may trigger policies by the public sector to bring about new (replacement or expansive) investments in generating capacity - with from a socio-economic cost perspective - low-risk technologies. In a liberalised market, adjustment of market framework conditions can bring this about.

2.6 Conclusions

In this chapter Markowitz Portfolio Theory (MPT) has been introduced as an approach to make allowance for mitigation of non-systematic risk by diversifying portfolios of financial assets. The same principle can be applied to portfolios of electricity generating technologies. From a long-term societal perspective the main risk associated with electricity generating options is the cost of electricity[15]: uncertainty over future cost realizations poses a serious risk, which should be considered when analyzing the evolution of a country's power mix. By applying MPT analysis, it can be shown that introducing options with risk characteristics that are largely unrelated with those of fossil-fuel-based generating technologies, such as renewables based options, mitigate portfolio risk.

Apart from the (Bar-Lev and Katz, 1976) article, application of MPT to portfolios of electricity generating technologies is relatively recent and still in development. In this chapter and accompanying annexes a number of refinements of the theoretical framework are presented. These relate to:

[15] To be more specific, the socio-economic cost of electricity after due internalisation of environmental impacts.

- Introduction of risk-cost efficient frontier.
- Use of energy-based as distinct from capacity-based portfolios.
- Expressing risk in terms of costs.
- Introduction of a consistent framework for determining the risk of COE for individual technologies.
- Incremental technology deployment analysis.

Finally, a stylized example is presented indicating how the graphical MPT output is to be interpreted.

It has been shown in this chapter, that by including portfolio (cost of electricity) risk, the MPT approach set out in this report enables policy makers to integrate the '*trias energetica*' (competitive energy prices, energy supply security, mitigation of adverse environmental impacts) in a quantitative framework. The proposed approach enables policy makers to monitor electricity cost risk developments using an energy supply security norm as yardstick, i.e. a pre-set upper bound to the real COE.

3. The Dutch generating mix in 2030

3.1 Introduction

CPB, the Netherlands Bureau for Economic Policy Analysis developed long-term scenario's for Europe and uses these scenarios for analysis of energy markets and climate policy (Bollen et al., 2004). Recently the scenarios have been used as a basis for a social cost-benefit analysis of large-scale implementation of offshore wind in the Dutch continental shelf (Verrips et al., 2005). As a side study to that report, this report also uses the long term CPB scenarios 'Strong Europe (SE)' and 'Global Economy (GE)' as a starting point for long-term portfolio analysis.

Section 3.2 describes a number of input assumptions and presents two alternative policy variants, which will be evaluated. Sections 3.3 and 3.4 present the efficient frontier and risk characteristics for scenarios SE and GE respectively. The final section will indicate some preliminary conclusions.

3.2 Scenarios, variants and input assumptions

In this analysis of future costs and risks there is a clear distinction between how the world may look like (i) *without* major policy changes and (ii) *after* specified changes of policy packages. The first aspect is translated into *scenarios*, which are plausible consistent descriptions of the future. Scenarios may be regarded as external to the model. As mentioned, this study builds on scenarios constructed by the CPB. The policy aspect on the other hand is less external, since it defines different approaches or strategies for dealing with external changes. Different policy strategies, including 'business-as-usual' are translated into *policy variants*.

This reports uses CBP scenarios SE and GE.[16] For each scenario, three variants are considered:

- *Reference (0):* a reference variant assuming continuation of renewables stimulation policy currently implemented or already officially announced to be implemented (SE0 and GE0 respectively). This variant is also referred to as the 'base case'.
- *Wind (p1):* an intensification of renewables stimulation policy, with the emphasis put on offshore wind energy stimulation (SEp1 and GEp1 respectively).
- *Biomass (p2):* an intensification of renewables stimulation policy, with the emphasis put on a broad variety of relatively cost-effective renewable technologies (SEp2 and GEp2 respectively).

In addition to identifying scenarios and policy variants, the model will need some prior information setting the initial situation and restricting possible outcomes. This prior information is translated into a set of *input assumptions*. All input data used in this study has been obtained from, and are consistent with, the data used in the cost-benefit analysis for off-shore wind conducted by CPB in association with ECN (Verrips et al., 2005). Constraints imposed on the model relate *inter alia* to the assumed technical potentials of the distinct renewable generating technologies, because of e.g. resource or authorization (notably, wind power) constraints.

Most technology cost assumptions are similar for both SE and GE. Only wind onshore and wind offshore have distinct cost assumptions. Cost-reducing technical progress for these technologies is assumed to occur at a faster rate (as captured by a lower progress ratio) under SE than under

[16] This choice was suggested by EZ so as to use broadly the same set of underlying assumptions as the social cost-benefit analysis of large-scale offshore wind study (Verrips et al., 2005). The input data used are quite comparable but not completely similar to the aforementioned study.

the GE scenario. However, since SE and GE have quite divergent assumptions on CO_2 price developments, the resulting total generating costs differ for many, notably fossil-fuel-based, technologies. Furthermore, total electricity demand is assumed higher under GE than under SE. Other assumptions are listed below. The feasible range of generating capacities, so-called *energy bounds* (see Annex H), are largely identical in energy terms, except for existing nuclear and coal. The bounds do however differ relatively, due to the higher energy demand in the GE scenario.

3.3 The Strong Europe (SE) scenario

Strong international cooperation and important public institutions are key characteristics of the Strong Europe (SE) scenario. In this scenario, European integration proceeds successfully, both politically, economically and geographically. Welfare distribution is valued over economic growth and cooperation will result in a stringent climate policy. Up to 2020 a CO_2 price of 11 $€_{2003}$/tonne is assumed, thereafter increasing to 55 $€_{2003}$/tonne in 2030. For gas a price of 4,7 $€_{2003}$/GJ is assumed in year 2030. Until 2030, primary energy demand is to increase at a (very) modest rate and CO_2 related emissions would decrease in absolute terms.

3.3.1 The SE0 base case

One of the key graphical results of portfolio analysis is construction of the efficient frontier (EF), a graph on which each point represents an efficient portfolio. Portfolio efficiency in this context means that no portfolio with lower costs (in terms of €/MWh) can be obtained without increasing risk.

For the SE0 variant the efficient frontier is depicted in Figure 3.1. Details characterising special points in this figure are presented in Table 3.1.

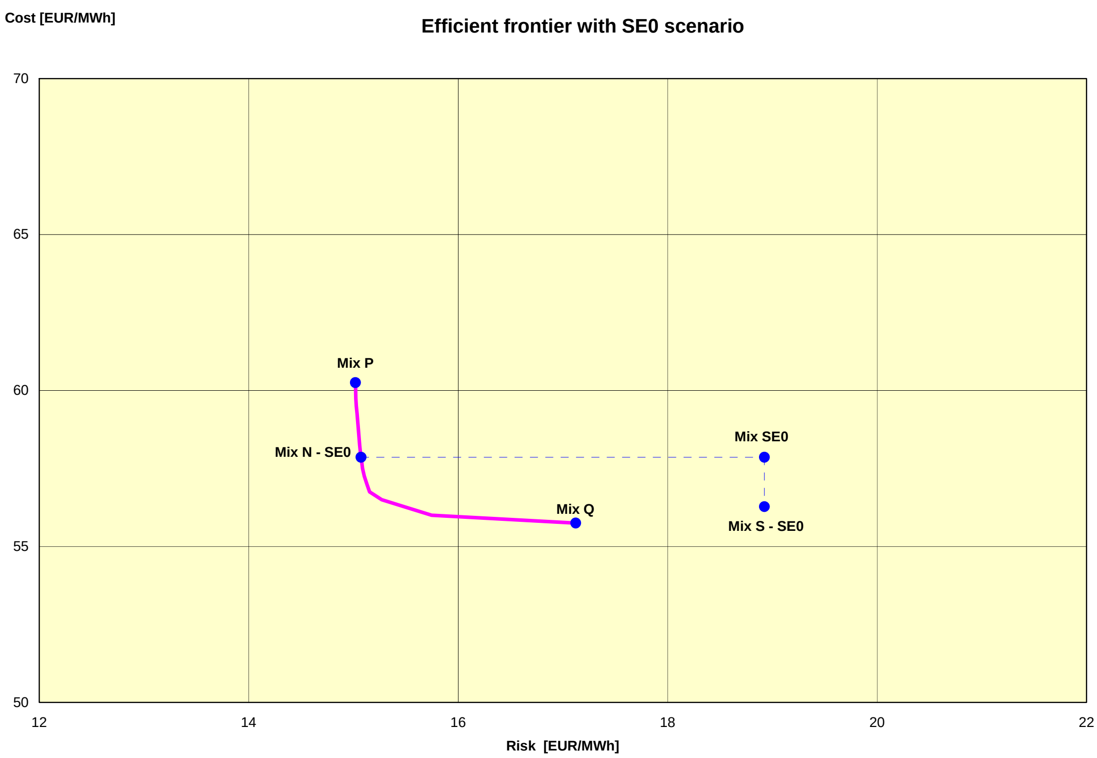

Figure 3.1 *Efficient frontier for SE0*

Table 3.1 *Aggregated results SE0*

		Mix P	Mix N - SE0	Mix SE0	Mix S - SE0	Mix Q
Portfolio cost	[€/MWh]	60.2	57.9	57.9	56.3	55.7
Portfolio risk σ	[€/MWh]	15.0	15.1	18.9	18.9	17.1
Upper bound at 2.5%	[€/MWh]	89.7	87.4	95.7	93.4	89.3
Gas CC	[%]	18.4	18.4	38.6	41.0	34.4
Gas CHP	[%]	37.2	37.2	37.2	38.1	38.1
Coal	[%]	12.1	12.7	21.7	11.5	1.5
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	20.0	20.0	0.0	4.2	20.0
Renewable biomass	[%]	10.5	10.5	1.5	4.2	4.9
Renewable other	[%]	1.7	1.1	1.0	1.1	1.1

Let us consider each characteristic point:

- Table 3.1: column Mix SE0). The *target mix* set for the SE0 is characterised by (expected) portfolio cost of 57.9 €/MWh and portfolio risk of 18.9 €/MWh. The odds are 1 against 40 (= 2.5%) that the target mix will end up in a portfolio electricity cost level exceeding 95.7 €/MWh (two sigma from the mean). As already explained in Section 2.5, the latter type of information may assist policy makers to define levels of cost risk that they consider acceptable. Renewables are poorly represented in the target mix: wind 0%, biomass 2%, and other renewables 0%.
- *Point S - SE0* is on the efficient frontier vertically below the target mix. The mix S - SE0 has the same risk as the target mix but its expected electricity cost are lower (56.3 €/MWh). As the target mix is rather risky, point S is situated on 'the inefficient part' of the efficient frontier (not shown in Figure 3.1). Somewhat counter-intuitively, more renewables-based electricity is represented in portfolio S - SE0. Coal (which is costly in the SE0 scenario due to the CO_2 price) is substituted by gas technologies, wind power and biomass options.
- *Point N - SE0* is on the efficient frontier horizontally to the left of the target mix. The mix N - SE0 has the same cost as the target mix but its expected risk level is much lower (15.1 €/MWh against 18.9 €/MWh). Renewables are well represented in this low risk portfolio: wind 20% (representing the total onshore and offshore potential), biomass 10% (also the full potential) and other renewables 1%.
- The lowest point of the efficient frontier is *point Q*. This point stands for the lowest expected cost portfolio (55.7 €/MWh). Note that its expected risk is appreciably lower than that of the target mix (17.1 €/MWh against 18.9 €/MWh). As renewables tend to be less cost risky than fossil-fuel-based electricity, while under SE their cost are assumed to come down importantly by 2030, renewables are represented rather well in mix Q: wind 20% (full potential), biomass 4%, and other 1%.
- The highest point of the efficient part of the efficient frontier is *point P*. This point stands for the lowest expected risk portfolio (15.0 €/MWh), but its expected cost is higher than associated with the target mix (60.2 €/MWh against 57.9 €/MWh). However, the upper bound at 2.5% percentile in Mix P (89.7 €/MWh) is lower than for the target mix (95.0 €//MWh). As renewables tend to be less cost risky than fossil-fuel-based electricity, renewables are represented quite well in portfolio P: wind 20%, bio 10%, and other 2% (the total renewable potential).

The relatively high expected carbon cost under the SE scenario (55 €/tCO_2 in target year 2030) has a strong impact on costs: even along the efficient frontier no portfolios can be found in the base case variant with lower expected electricity cost than 55.7 €/MWh. Furthermore, the shape of the efficient frontier is rather hollow making that over a wide range from right below (point Q) to left, large (expected) risk reductions can be obtained at relatively small cost sacrifices (hence slightly higher expected costs), up to a point where the efficient frontier bends steeply upward. The explanation of this shape may relate to almost 'free lunches' that can be obtained initially by moving from Q to the left along the efficient frontier, notably by substitution of gas by coal and biomass co-firing.

3.3.2 The variants SEp1 and SEp2

A striking feature under SE is, that the target mixes for variants p1 (renewables with offshore wind focus) and p2 (broad-based renewables) not only are much less risky than for the *base case* policy variant, but are also characterised by slightly lower expected electricity cost. The carbon factor under SE appears to have a rather high impact, rendering the economics of renewables-based technology *vis-à-vis* fossil-fuels-based ones much better for RES-E generators. Furthermore, the (expected) portfolio cost-risk differences between target mixes p1 and p2 are rather small: SE-p1 has slightly higher costs on the one hand, but slightly lower risk on the other.

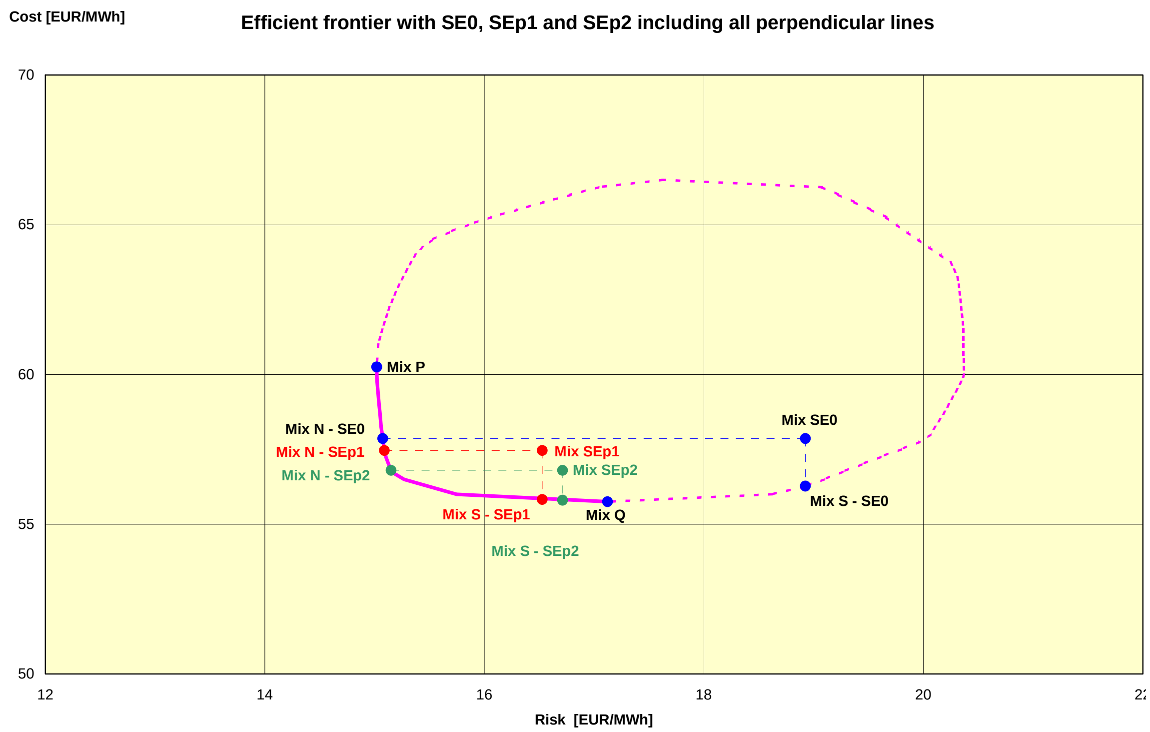

Figure 3.2 *Efficient frontier for SE0, SEp1 and SEp2*

Table 3.2 *Aggregated results SEp1*

		Mix P	Mix N - SEp1	Mix SEp1	Mix S - SEp1	Mix Q
Portfolio cost	[€/MWh]	60.2	57.5	57.5	55.8	55.7
Portfolio risk σ	[€/MWh]	15.0	15.1	16.5	16.5	17.1
Upper bound at 2.5%	[€/MWh]	89.7	87.0	89.9	88.2	89.3
Gas CC	[%]	18.4	18.4	24.2	28.7	34.4
Gas CHP	[%]	37.2	37.2	37.4	38.1	38.1
Coal	[%]	12.1	12.7	21.7	7.2	1.5
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	20.0	20.0	14.0	20.0	20.0
Renewable biomass	[%]	10.5	10.5	1.5	4.9	4.9
Renewable other	[%]	1.7	1.1	1.1	1.1	1.1

Table 3.3 *Aggregated results SEp2*

		Mix P	Mix N - SEp2	Mix SEp2	Mix S - SEp2	Mix Q
Portfolio cost	[€/MWh]	60.2	56.8	56.8	55.8	55.7
Portfolio risk σ	[€/MWh]	15.0	15.2	16.7	16.7	17.1
Upper bound at 2.5%	[€/MWh]	89.7	86.5	89.6	88.6	89.3
Gas CC	[%]	18.4	18.4	24.2	30.5	34.4
Gas CHP	[%]	37.2	37.2	38.1	38.1	38.1
Coal	[%]	12.1	13.5	21.7	5.4	1.5
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	20.0	20.1	13.4	20.1	20.0
Renewable biomass	[%]	10.5	9.7	1.5	4.9	4.9
Renewable other	[%]	1.7	1.1	1.1	1.1	1.1

3.4 The Global Economy (GE) scenario

The Global Economy (GE) scenario is characterised by strong international cooperation and an important role for private responsibilities. Economic growth is valued over government interference beyond providing a limited amount of public goods. Integration is limited to the economic sphere and cooperation in non-trade issues, like effective climate policy, fails. Up to 2020 a CO_2 price of 11 €/tonne is assumed, while as from 2021 the carbon market is assumed to collapse under the GE scenario with a 0 €/tonne price for CO_2 emission allowances. For gas a price of 4,7 $€_{2003}$/GJ is assumed in year 2030. Until 2030, primary energy demand will increase at a steady 2.3%, as will emissions.

3.4.1 The GE0 base case

The shape of the efficient frontier under the GE scenario is less concave than under SE, while it is situated much lower. The carbon factor (expected carbon cost in target year 2030 of € 0 €/tCO_2) is a major undercurrent accounting for the latter feature. As the economics of renewables is much less favorable under GE (again on account of the assumed negligible carbon costs but for wind also because of assumed slower technological progress), under GE penetration of RES-E is projected to be much slower. The information contained on the special points in Figure 3.3 and Table 3.4 bears this out.

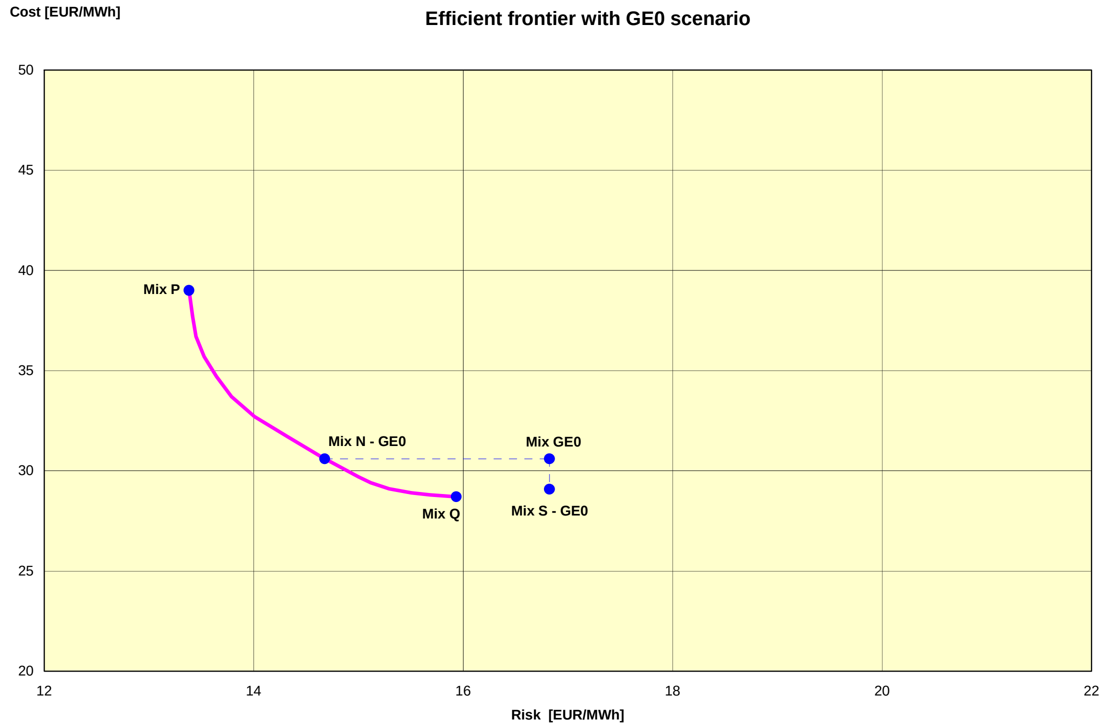

Figure 3.3 *Efficient frontier for GE0*

Only mix N on the efficient frontier, horizontally left from the *base case* target mix GE0, and even more so mix P (the least risky portfolio feasible under scenario GE) have an appreciable uptake of RES-E. As under GE RES-E technology tends to be much more expensive than fossil-fuel technology if at typically much lower risk, the Sharpe ratio (cost change per unit of risk change: the slope of the efficient frontier) is initially much less favourable, when moving along the efficient frontier to the left departing from Q. On the other hand, in GE the constraints to RES-E deployment imposed upon the model are reached at a much later phase when moving upward along the efficient frontier from Q, right under, to P, top left. Hence, on the least risky (upper left) part RES-E is better placed to accommodate risk aversion by moving leftward under GE then under SE.

Table 3.4 *Aggregated results GE0*

		Mix P	Mix N - GE0	Mix GE0	Mix S - GE0	Mix Q
Portfolio cost	[€/MWh]	39.0	30.6	30.6	29.1	28.7
Portfolio risk σ	[€/MWh]	13.4	14.7	16.8	16.8	15.9
Upper bound at 2.5%	[€/MWh]	65.2	59.4	63.6	62.1	59.9
Gas CC	[%]	11.4	11.4	25.1	26.4	15.3
Gas CHP	[%]	31.1	31.1	32.8	32.8	32.8
Coal	[%]	29.4	45.1	40.0	37.6	48.3
Nuclear	[%]	1.1	1.1	1.1	1.1	1.1
Renewable wind	[%]	16.8	6.6	0.0	1.3	1.7
Renewable biomass	[%]	8.8	3.7	0.1	0.0	0.0
Renewable other	[%]	1.4	0.9	0.9	0.9	0.9

Compare, for example, mix N under GE (in Table 3.4) with mix N under SE (in Table 3.1) and check the corresponding RES-E shares. The shares of wind (20%) and biomass (10%) in N under SE appears to have increased to their (model imposed) upper limits, while under GE (wind 7%, bio 4%) this is not the case by far. This underscores that under GE renewables can accommodate risk reduction at low risk levels better than under SE where they are already stretched to the limit at low risk levels.

3.4.2 The variants GEp1 and GEp2

A remarkable difference between the location of target mixes under the GE variants p1 (wind) and p2 (biomass) and those of their SE counterparts is, that under GE their associated expected electricity cost is (somewhat) higher than the corresponding zero (base case) target mix. This can be gleaned from Figure 3.4 as well as from Table 3.2 and Table 3.3 respectively. Evidently, the costs of deliberate market forcing of RES-E are much higher under GE where help of the carbon factor is of no avail.

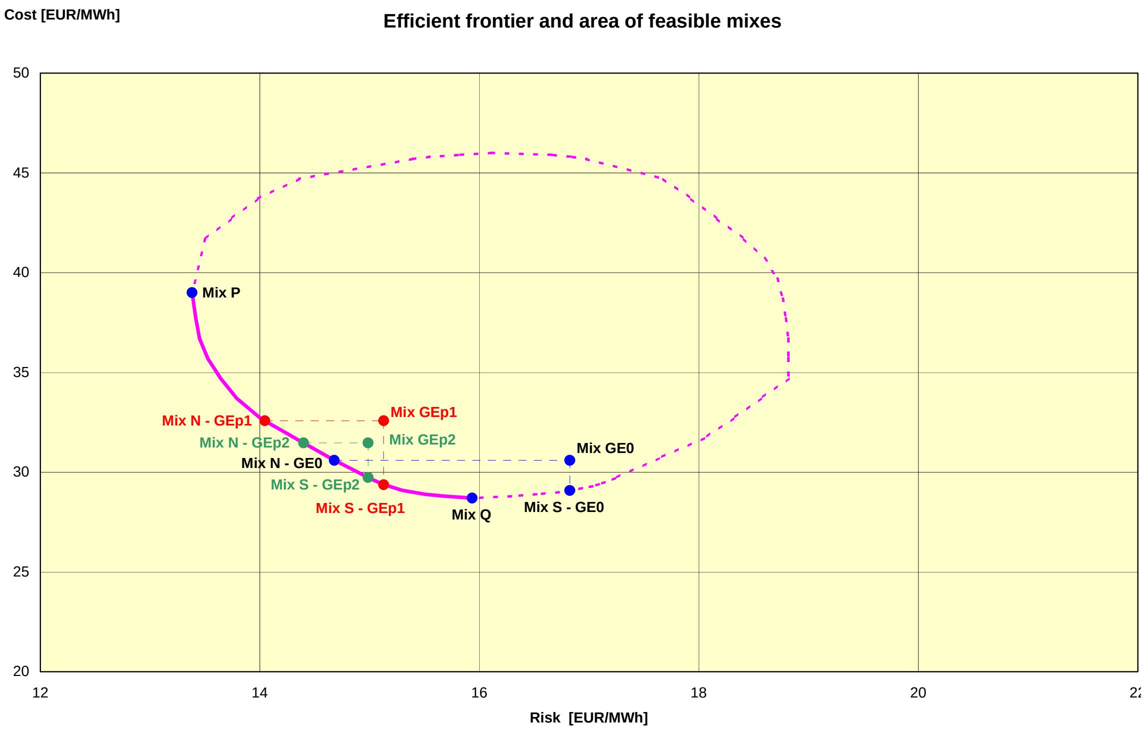

Figure 3.4 *Efficient frontier and feasible mixes GEp1 and GEp2*

Table 3.5 *Aggregated results GEp1*

		Mix P	Mix N - GEp1	Mix GEp1	Mix S - GEp1	Mix Q
Portfolio cost	[€/MWh]	39.0	32.6	32.6	29.4	28.7
Portfolio risk σ	[€/MWh]	13.4	14.0	15.1	15.1	15.9
Upper bound at 2.5%	[€/MWh]	65.2	60.1	62.2	59.0	59.9
Gas CC	[%]	11.4	11.4	18.5	11.4	15.3
Gas CHP	[%]	31.1	31.1	32.2	31.1	32.8
Coal	[%]	29.4	38.3	35.4	49.8	48.3
Nuclear	[%]	1.1	1.1	1.1	1.1	1.1
Renewable wind	[%]	16.8	13.4	11.7	2.0	1.7
Renewable biomass	[%]	8.8	3.7	0.1	3.7	0.0
Renewable other	[%]	1.4	0.9	0.9	0.9	0.9

Table 3.6 *Aggregated results GEp2*

		Mix P	Mix N - GEp2	Mix GEp2	Mix S - GEp2	Mix Q
Portfolio cost	[€/MWh]	39.0	31.5	31.5	29.7	28.7
Portfolio risk σ	[€/MWh]	13.4	14.4	15.0	15.0	15.9
Upper bound at 2.5%	[€/MWh]	65.2	59.7	60.8	59.1	59.9
Gas CC	[%]	11.4	11.4	16.3	11.4	15.3
Gas CHP	[%]	31.1	31.1	32.3	31.1	32.8
Coal	[%]	29.4	42.1	37.6	48.3	48.3
Nuclear	[%]	1.1	1.1	1.1	1.1	1.1
Renewable wind	[%]	16.8	9.6	11.2	3.4	1.7
Renewable biomass	[%]	8.8	3.7	0.7	3.7	0.0
Renewable other	[%]	1.4	0.9	0.9	0.9	0.9

3.5 Conclusions

In this chapter, the reference policy variant and two ‘renewables promotion’ policy variants have been analyzed for MPT efficiency, using the ‘Strong Europe’ (SE) and ‘Global Economy’ (GE) scenarios. In line with the assumptions underlying the scenarios, both cost of electricity and associated risk in GE are generally lower than in SE, due to learning rates in technological development and the content of future climate policy. Differences in scenarios are clearly reflected in the shape and position of the feasible areas.

Results of portfolio analysis performed indicate that:

- In both scenarios, the base variant is not very efficient and graphical analysis suggests that diversification may yield up to 20% risk reduction at no extra cost.
- Stimulation of renewable energy, as described in policy variants p1 and p2, can greatly improve the cost risk. Even in the GE scenario - the one that is rather unfavourable to a take-off of renewables-based technology - this can be achieved at little additional costs. For the SE scenario, portfolio cost in the renewables policy variants is lower than the one in the zero variant.
- Defining mixes without intensification of renewables stimulation (i.e. the zero variant target mixes) would result in riskier mixes (about 10% risk reduction is possible compared to the alternative policy variants 1 and 2) while portfolio costs would not be materially affected (about 6% cost increase for GEp1, 3% cost increase for GEp2, small cost reduction of 1% to 2% for SEp1 and SEp2).
- Further optimization beyond the variants evaluated is possible. However, the largest increase has already been realized with the relatively straightforward policy options p1 or p2.
- All in all, results indicate that intensification of renewables stimulation policy can be justified from a socio-economic perspective. In the SE scenario, the choice for p1 or p2 depends on risk aversion preferences: p1 is indicated to be slightly less riskier but also slightly costlier. In the GE scenario the results presented above indicate that policy variant p2 would be socio-economically slightly more favourable than p1.

The next chapter will consider how robust these outcomes are.

4. Sensitivity analysis

4.1 Introduction

As noted before, the uncertainties underlying cost and risk estimates are substantial. It is therefore important to interpret the results of the MPT analysis with great care. This chapter applies some sensitivity analyses, evaluating the sensitivity of the outcomes as a result of variations in the input parameters.

First CO_2 price variations are investigated as the value differs significantly between the two scenarios and there is still much uncertainty on what the appropriate value in 2030 can be. The second section determines the variation in outcome as a result of variations on the gas price. As current and future Dutch generating mixes are set to have a large share of natural gas, this is a potentially important factor. Section four discusses the changes in biomass prices, directly affecting the co-firing share, and the resulting effects on cost and risk.

Even though offshore wind is both more costly and more risky than onshore wind, the physical potential of the latter is limited. This section will investigate the risk reduction potential of offshore wind on the total generating portfolio. The effect will be evaluated by stepwise enforcing a fixed amount of offshore wind in the mix.

4.2 Sensitivity to CO_2 price variations

In the GE scenario, the price of CO_2 emission allowances is set to 0 €/tCO_2 in year 2030. This obviously has an effect on the penetration of renewable energy sources in the optimised mixes. Fossil fuelled generating technologies are not penalized for their emission. At the same time the assumed learning rate of wind power is moderate (i.e. investment cost decrease less in GE than in SE), which makes that the share of renewable is not so very high: for GE 2% in mix S and 12% in mix N (Table B.1).

Hereafter the sensitivity of main results under GE are considered by increasing the CO_2-price to 25 €/tCO_2 (Table B.2) and 55 €/tCO2 (Table B.3) respectively. Note, that the latter carbon price level is equal to the level assumed in the SE-scenario, which makes that the results for this run become rather closely comparable to SE (the only remaining key difference is wind power costs and the total generation volume (TWh)).

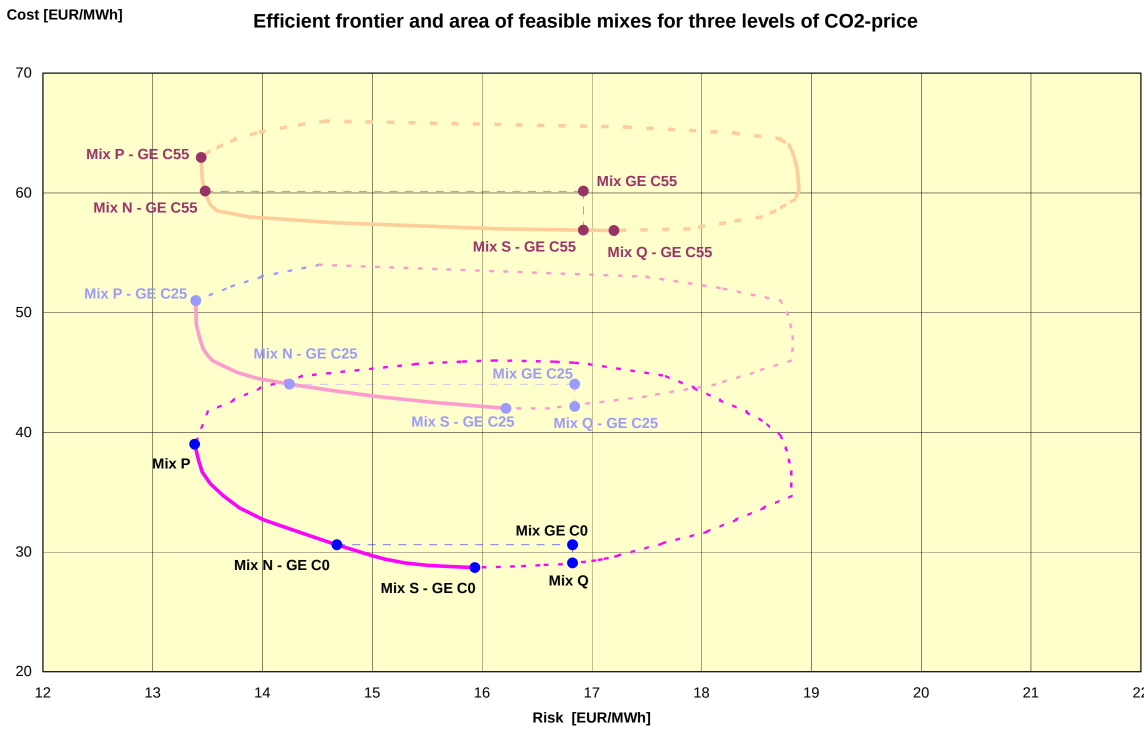

Figure 4.1 *Efficient frontier and mixes for different CO_2 prices*

The graphical presentation of the main results (Figure 3.4) confirm - as do the numerical data in Table B.2 and Table B.4 - the broad picture that SE in relation to GE results yields concerning the carbon factor. The price of carbon is of key importance to the cost at which the energy supply security in the power sector can be improved through a (up till 2030 still partial) transition from fossil-fuel-based generation technology to renewables-based generation technology. A carbon price under GE rising *ceteris paribus* from 0 €/tCO_2 to 55 €/tCO_2 will dramatically improve the market position of, notably, offshore wind as well as certain relatively low-cost, high-potential biomass technologies.

Capacity constraints (attempted to be imposed to our model as realistically as possible given currently available information) rather than technology cost factors appear to limit the penetration of renewables under a 'high' (55 €/tCO_2) carbon price. This can be gleaned again by the efficient frontier, assuming an increasingly hollow shape moving from the 0 €/tCO_2 through the 25 €/tCO_2 to the 55 €/tCO_2 GE one. Incidentally, a 55 €/tCO_2 price reflects a fairly, not extremely stringently, carbon-constrained economy given the 25 years long time period ahead. This is consistent with a medium-level priority for Climate Change policy.

4.3 Sensitivity to gas price variations

Whereas increasing the carbon costs (presented in Section 0) has an impact on all fossil fuelled technologies, increasing only the gas price leaves all options untouched, except CCGT baseload and peak load plants and CHP. And since gas options are of considerable importance in the SE0 scenario (76%), the expected portfolio cost will increase considerably.

The sensitivity to the gas price is evaluated using the SE scenario as a reference. In this reference case the gas price is 4.7 €/GJ. The 'high gas' case has a gas price of 10 €/GJ, more than double the reference value. Remember that the target year for the current exercise is the year 2030. It would seem that, certainly from a precautionary perspective, in such a distanced future gas prices on the order of 10 €/GJ cannot be excluded. For calculating the associated unfavourable fuel cost risk for gas technologies a projected upper bound limit needs to be defined in either case.

Table 4.1 *Gas prices in 2030*

[$€_{2003}$ /GJ]	Mean	High
Gas base case	4.7	10.0
High gas price	10.0	20.0

Note: the Dutch wholesale gas price per ultimo year 2005 hovers around $€_{2003}$ 4.7.

Due to the important share of gas in the SE0-mix the expected portfolio cost and risk increase considerably. Cost increase from 57.9 to 81.1 €/MWh and risk from 18.9 to 33.6 €/MWh. Given these high expected portfolio cost and the shape of the area in which allowed mixes can be located, it can be seen that the strategic points S (equal risk level) and N (equal cost level) are located on the inefficient part of the frontier. The variants SEp1 and SEp2 however are much more diversified, and less vulnerable to high gas prices. They are, however, still much less favourable in terms of portfolio cost and risk than in the base case.

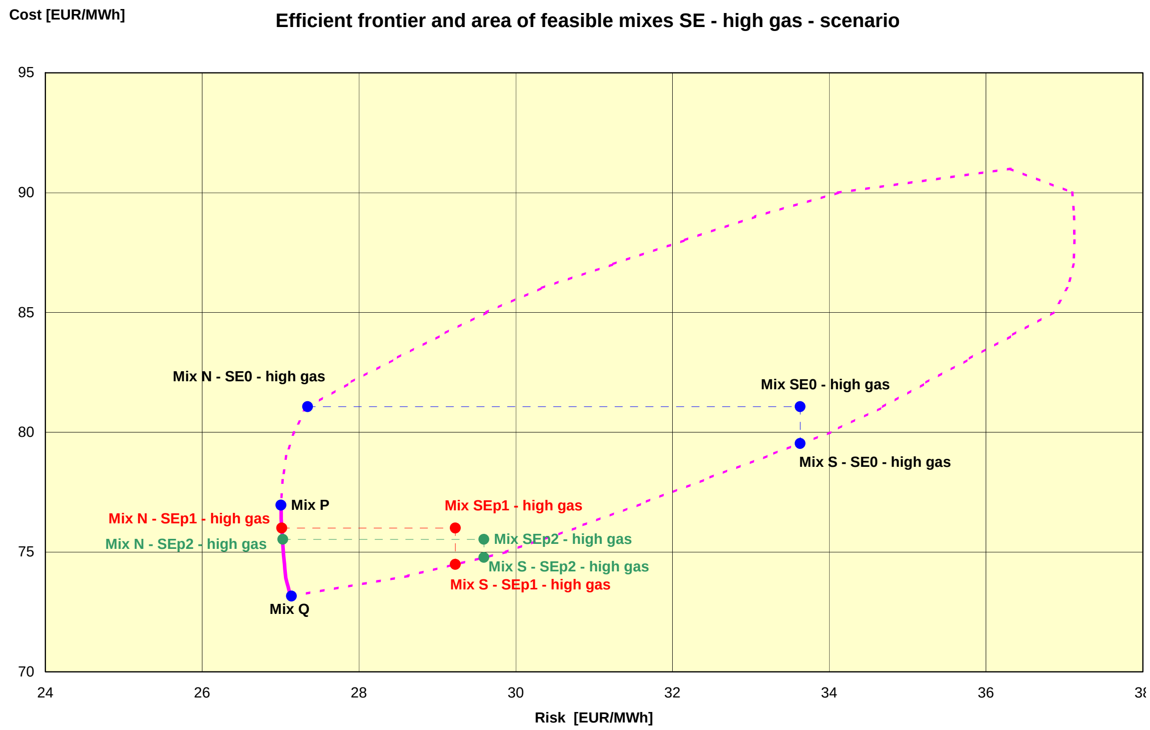

Figure 4.2 *Efficient frontier SE (high gas)*

As the efficient frontier is at the same time very steep, there is not much difference in risk between mixes P and Q. Also, the options in the mix are very similar: mix Q can be cheaper than mix P by substituting coal for biomass. For this reason, the portfolios N-SEp1 and N-SEp2 are very similar to Mix P.

It is interesting to see that in Mix S (equal risk - lowest costs for this risk) for SE0 a share of 6% is generated from wind energy (mainly from 4 GW installed capacity onshore) and 5% from biomass (1 GW installed capacity). Under the SE-assumptions with a high gas price such a penetration rates will yield a considerable improvement compared to SE0. For SEp1 and SEp2 the corresponding rates are even higher for wind: 10 to 12%.

4.4 Sensitivity to biomass price variations

Fore studying the sensitivity to the biomass price, only the fuel price for co-firing has been increased: from 5 €/GJ tot 10 €/GJ.

Table 4.2 *Biomass prices in 2030 (SE scenario)*

[€/GJ]	Mean	High
Biomass (co-firing)	5.0	7.0
Biogas (co-firing)	0.0	2.0
Biomass small	4.0	6.0

Table 4.3 *Biomass prices (high)*

[€/GJ]	Mean	High
Biomass (co-firing)	10.0	14.0

As the biomass share in the SE0 mix is very small (and for co-firing even zero), increasing the biomass price for co-firing does not affect the characteristics of SE0. It can be seen from the tables that mainly Mixes N and P are subject to a reduction of the biomass penetration due to the price increase.

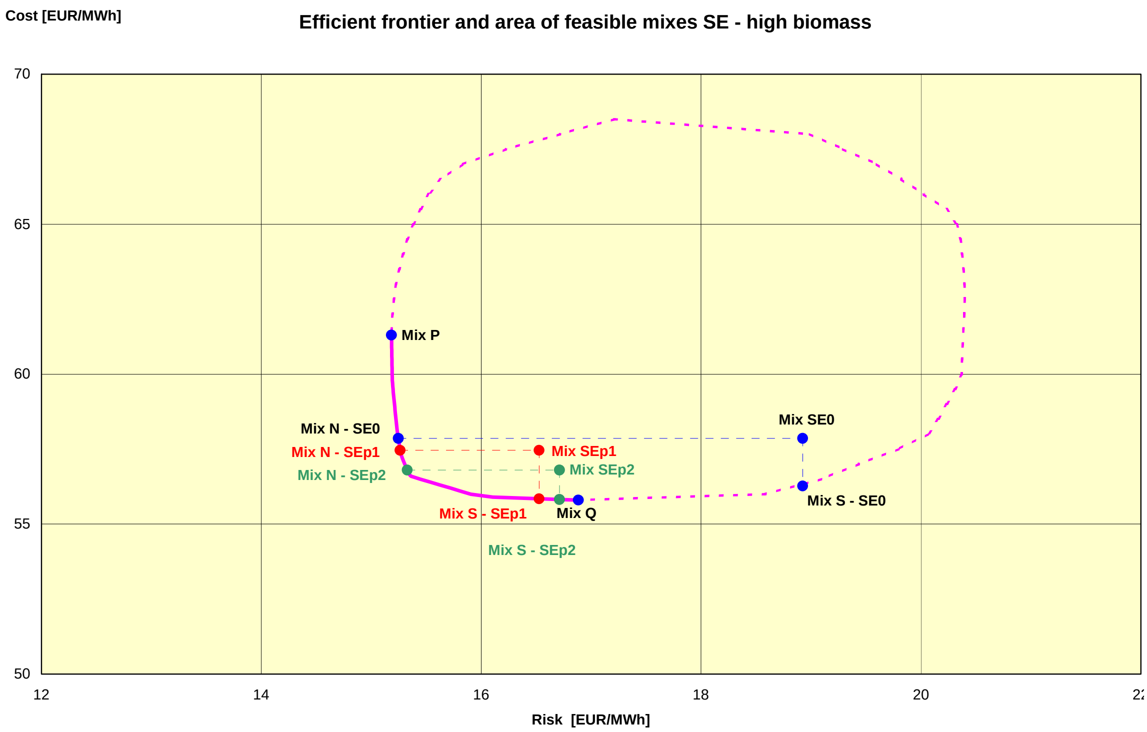

Figure 4.3 *Efficient frontier and mixes SE (high biomass)*

4.5 Sensitivity to off shore wind constraints

In this section, focus is on the SEp1 variant, and especially on the Mix N, while the constraint on offshore wind is tightened from 6 GW to 1 GW.

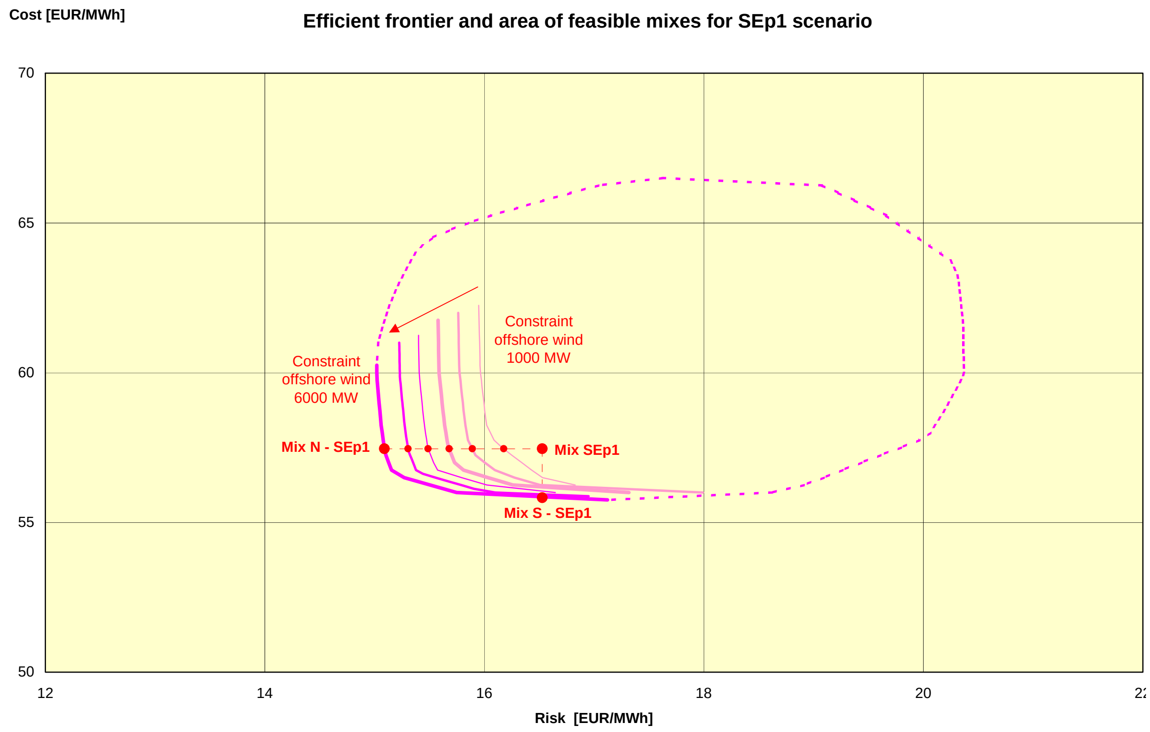

Figure 4.4 *Efficient frontier for different wind constraints*

In Mix SEp1 (offshore constraint 6 GW) the wind share is 14%, consisting of the full offshore wind potential: 21 TWh or 6000 MW. The onshore wind share is 0%. The aim of the current exercise is to step-wise tighten the potential for offshore wind penetration (by 1 GW per step) and to allow the portfolio to be reshuffled. It can be seen that also with tighter constraints the portfolio risk still can be decreased.

For example, allowing only 2000 MW the minimum portfolio risk can still be reduced from 16.5 €/MWh (portfolio risk for SEp1 target mix) to 15.9 €/MWh (lowest risk at same portfolio cost). This is done by simultaneously increasing the share of biomass and reducing the gas share.

Another interesting mix is the one with an equal wind share as in SEp1 (14.0%), but with a smaller amount of offshore wind. From the table below it can be seen that the offshore wind constraint will then have to be put somewhere in between 3000 and 4000 MW. In this case, the assumed onshore wind potential would be fully exploited at the same time.

Table 4.4 *Aggregate results SEp1, different wind offshore constraints*

		Mix N - 1000 MW	Mix N - 2000 MW	Mix N - 3000 MW	Mix N - 4000 MW	Mix N - 5000 MW	Mix N - SEp1
Portfolio cost ()	[€/MWh]	57.5	57.5	57.5	57.5	57.5	57.5
Portfolio risk σ	[€/MWh]	16.2	15.9	15.7	15.5	15.3	15.1
Upper bound at 2.5%	[€/MWh]	89.2	88.6	88.2	87.8	87.5	87.0
Gas CC	[%]	19.2	18.4	18.4	18.4	18.4	18.4
Gas CHP	[%]	37.2	37.2	37.2	37.2	37.2	37.2
Coal	[%]	25.2	23.2	20.4	18.0	15.6	12.7
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	7.8	10.2	12.5	14.9	17.2	20.0
Renewable biomass	[%]	9.5	9.9	10.4	10.5	10.5	10.5
Renewable other	[%]	1.1	1.1	1.1	1.1	1.1	1.1

4.6 Conclusions

In this chapter the effects of variation of a number of input parameters on the cost and risk of the generating mixes are investigated. Due to uncertainty surrounding cost and risk, the results of this study are to be treated with caution. To put these in due uncertainty perspective, sensitivity analysis is a quite valuable tool.

The price of carbon (CO_2) is of key importance to the additional cost at which the security of supply in the power sector can be improved by moving towards an increasing share for renewables based options. A higher carbon price dramatically improves the market position of renewables. As indicated in Figure 4.1, an increase in the price of carbon tilts and shifts the efficient frontier upward.

Due to the large share of natural gas in the SE0 generating mix, expected portfolio cost and risk increase considerably. Under the assumption of 'high' gas prices (high as compared to the CPB SE and GE scenarios), the risk mitigating potential for renewables based generating options is highly amplified. Hence, the sensitivity of renewables based generation technologies for the gas price is quite high.

Since biomass is only considered in co-firing and the share is limited, variations in the price have little effect on either costs or risk. With an increasing biomass price, the mix shifts towards a larger share of coal.

Finally, the sensitivity analysis shows that offshore wind - because of its relative low risk and high potential - can significantly reduce portfolio risk. Under the SE scenario assumptions, tightening the technical offshore wind constraints results in higher coal shares. Also, from 1 GW up to 6 GW every discrete relaxation of the offshore wind constraint by 1 GW increments at a time has the same marginal risk reduction potential.

Results of sensitivity analyses that have been shown in this chapter indicate that the characteristic of renewables-based technology to reduce portfolio risk is rather robust. This not only holds for broad-based renewables stimulation strategy but for strategies with a certain focus on off-shore wind. Secondly, the economics of renewables-based generating technologies are quite sensitive to the evolution of the gas price. In this respect, it is recalled that both the GE and the SE scenario assume a rather moderate gas price evolution.

Let us conclude by a general observation. The large distances of target mixes from their corresponding efficient frontier under the distinct scenario variants and the uncertainties underlying the technology cost and potential assumptions suggest that it is quite hard for policymakers to impose the right framework conditions to the market that lead to socially optimal portfolios. Nevertheless, reducing - under scenarios of rising real-term fossil fuel prices and increasingly binding carbon constraints - long-term (electricity) cost risk and long-term cost rise by renewables R&D and market stimulation would seem appropriate as such.

5. Conclusions

5.1 Analysis of generating mix scenarios for the Netherlands; year 2030

MPT analysis is performed with respect to projected generating mixes in the Netherlands in 2030 under different scenarios and policy variants, with special reference to renewable electricity development.

5.1.1 A note on the assumptions

Technology costs have been chosen in accordance with the cost-benefit analysis study for offshore wind (Verrips et al., 2005). Input data have been composed with utmost attention and care, but the true future costs remain highly dependant on external factors. Scenario parameters such as reference mixes, CO_2 price and gas price assumptions have been chosen in line with the above-mentioned study and can be subject of discussion.

Risk estimates are derived following a pre-defined methodology and projections of long-term cost and risk for generating options specifically and portfolios at large remain difficult, even under the most state-of-the-art approaches. Furthermore, fuel correlations and technology parameter correlations are indicative and based on expert judgements.

5.1.2 Key results of the analysis

Of all pre-defined target portfolios for the year 2030 none is efficient in the sense deployed in this study: for each portfolio, reductions in either cost or risk or both are possible. In most cases, risk reductions and cost reductions can be obtained by increasing the share of renewable generating options (notably wind power and biomass). These opportunities can be quantified as a 20% risk reduction and a 4% cost reduction (Table 5.1, Table 5.2). Defining mixes without renewables results in riskier mixes (about 10% risk reduction is possible, Table 5.3, Table 5.4)

Table 5.1 *Potential diversification effect GE0*

	GE0	Minimum	Reduction [%]
Portfolio risk	*16.8*	13.4 (mix P)	20
Portfolio cost	*30.6*	28.7 (mix Q)	6

Table 5.2 *Potential diversification effect SE0*

	SE0	Minimum	Reduction [%]
Portfolio risk	*18.9*	15.0 (mix P)	21
Portfolio cost	*57.9*	55.7 (mix Q)	4

Table 5.3 *Potential diversification effect GEp1/GEp2*

	Mix GE0	Mix GEp1	Reduction [%]	Mix GEp2	Reduction [%]
Portfolio risk	*16.8*	15.1	10	15.0	11
Portfolio cost	*30.6*	32.6	-6	31.5	-3

Table 5.4 *Potential diversification effect SEp1/SEp2*

	Mix SE0	Mix SEp1	Reduction [%]	Mix SEp2	Reduction [%]
Portfolio risk	*18.9*	16.5	13	16.7	12
Portfolio cost	*57.9*	57.5	1	56.8	2

The outcome is very sensitive to CO_2 price assumptions. In the SE scenario, with prices of 55 €/ton the renewable options become much more competitive than in the GE scenario, with zero carbon costs. The relative importance of gas-fuelled power plants (58% in GE0 and 76% in SE0) poses a quite serious cost risk for the Dutch electricity sector. Renewables can considerably reduce cost risk of the generating portfolio. The impact on risk and cost is strongly dependant on the scenario assumptions (notably the CO_2 price, the gas price and, to a lesser extent, the coal price) and the cost assumptions of renewables.

5.2 Theoretical contributions

The analysis approach set out in this report is based on the methodology explained in Berger (2003) and Awerbuch and Berger (2003), and pioneered by Shimon Awerbuch in the 1990s. A number of methodological refinements have been proposed. These have been implemented in this study, some also in other ongoing or recently concluded research projects. The following contributions have been presented in this report:

- Introduction of an advanced notion of the efficient frontier based on cost.
- Use of energy based instead of generating capacity based portfolios.
- Expression of risk in terms of costs instead of a percentage rate.
- Consistent determination of risk associated with generating costs for distinct technologies.
- Incremental technology deployment analysis.

5.3 Agenda for further research[17]

This report has documented some major improvements of one-period analysis of generating technology portfolios through application of MPT. Focal research issues to further enhance the reliability and widen the scope of applications for the MPT approach in the domain of electricity and energy mix portfolios include:

- Improving the use of historical cost information to derive projections of future risk values. For example, incorporating GARCH techniques (e.g. Humphreys and McClian, 1998).
- Improving the methodology to derive the projected correlation matrix, showing the assumed interrelationships between portfolio cost components.
- Improving allowance made for the cost impacts of penetration of intermittent renewable resources, which warrants *inter alia* a segmentation of the power market (into peak, intermediate, base load categories) and renewable resources (e.g. average wind speed categories,

[17] This section is partly based on Jansen (2003).

average insolation categories) and specification of contributions to ancillary power provision services.
- Expanding the environmental adders cost component with inclusion of the cost of non-GHG polluting emissions such as NO_x and SO_2.
- Conversion from one-period analysis to multi-period analysis, permitting not only the identification of efficient portfolios in a certain target year but the determination of optimal trajectories for rebalancing portfolios from the base year to the target year. This would warrant specification of generation plant vintage years. Some leads are presented in Steinbach (2001) and Kleindorfer and Li (2005).
- Introducing MPT portfolio analysis for electricity sector expansion planning from the perspective of (large) electricity generators. The underlying portfolios of the efficient frontier concerned would maximise financial returns to these stakeholders, given portfolio risk levels. Such analysis would include electricity market modelling.

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Appendix A Input assumptions

This Annex presents a concise overview of the assumptions used in this report.

Table A.1 *Technology specific upper- and lower bounds of electricity generation (2030)*

[TWh]	SE		GE	
	Lower bound	Upper bound	Lower bound	Upper bound
Gas CC	35.3	96.1	11.4	46.8
Gas CHP	71.3	72.9	31.1	32.8
Coal	0.0	83.3	0.0	55.7
Nuclear	0.0	0.0	1.1	1.1
Renewable wind	0.0	38.4	0.0	16.8
Renewable biomass	0.0	20.1	0.0	8.8
Renewable other	0.0	3.4	0.0	1.5

Table A.2 *Estimated fuel costs (2030)*

[€/GJ]	Mean	High
Gas	4.70	10.00
Coal	1.70	3.00
Uranium	2.22	3.00
Biomass (co-firing)	5.00	7.00
Biogas (co-firing)	0.00	2.00
Biomass small	4.00	6.00

Table A.3 *Correlations fuel costs, expert opinions*

	Gas	Coal	Uranium	Biomass	Renewable
Gas	1.0	0.7	0.2	0.4	0.0
Coal	0.7	1.0	0.4	0.4	0.0
Uranium	0.2	0.4	1.0	0.1	0.0
Biomass	0.4	0.4	0.1	1.0	0.0
Renewable	0.0	0.0	0.0	0.0	1.0

Table A.4 *Correlations non-fuel costs, expert opinions*

	Investment	Variable O&M	Fixed O&M	CO_2
Investment	0.5	0.0	0.0	0.0
Variable_OM	0.0	0.5	0.0	0.0
Fix_OM	0.0	0.0	0.5	0.0
CO_2	0.0	0.0	0.0	1.0

Table A.5 *CO_2 costs/emission estimates*

	CO_2 emission [kg/GJ]	Mean [€/ton]	High [€/ton]
Gas	56.1		
Coal	94.7		
CO_2-price SE		55.0	85.0
CO_2-price GE		0.0	30.0

Appendix B Sensitivity analysis

Table B.1 *Aggregated results GE, 0 €/tCO₂*

		Mix P	Mix N - GE 0 €/tCO_2	Mix GE 0 €/tCO_2	Mix S - GE 0 €/tCO_2	Mix Q
Portfolio cost	[€/MWh]	39.0	30.6	30.6	29.1	28.7
Portfolio risk σ	[€/MWh]	13.4	14.7	16.8	16.8	15.9
Upper bound at 2.5%	[€/MWh]	65.2	59.4	63.6	62.1	59.9
Gas CC	[%]	11.4	11.4	25.1	26.4	15.3
Gas CHP	[%]	31.1	31.1	32.8	32.8	32.8
Coal	[%]	29.4	45.1	40.0	37.6	48.3
Nuclear	[%]	1.1	1.1	1.1	1.1	1.1
Renewable wind	[%]	16.8	6.6	0.0	1.3	1.7
Renewable biomass	[%]	8.8	3.7	0.1	0.0	0.0
Renewable other	[%]	1.4	0.9	0.9	0.9	0.9

Table B.2 *Aggregated results GE, 25 €/tCO_2*

		Mix P	Mix N - GE 25 €/tCO_2	Mix GE 25 €/tCO_2	Mix S - GE 25 €/tCO_2	Mix Q
Portfolio cost (€/MWh)	[€/MWh]	51.0	44.0	44.0	42.2	42.0
Portfolio risk σ (€/MWh)	[€/MWh]	13.4	14.2	16.8	16.8	16.2
Upper bound at 2.5% (€/MWh)	[€/MWh]	77.3	72.0	77.0	75.2	73.8
Gas CC	[%]	11.4	12.8	25.1	26.7	21.8
Gas CHP	[%]	31.1	31.1	32.8	32.8	32.8
Coal	[%]	29.4	37.6	40.0	36.8	37.6
Nuclear	[%]	1.1	1.1	1.1	1.1	1.1
Renewable wind	[%]	16.8	12.4	0.0	1.7	2.1
Renewable biomass	[%]	8.8	4.1	0.1	0.0	3.7
Renewable other	[%]	1.5	0.9	0.9	0.9	0.9

Table B.3 *Aggregated results GE, 55 €/tCO$_2$*

		Mix P	Mix N - GE 55 €/tCO$_2$	Mix GE 55 €/tCO$_2$	Mix S - GE 55 €/tCO$_2$	Mix Q
Portfolio cost	[€/MWh]	62.9	60.1	60.2	56.9	56.8
Portfolio risk σ	[€/MWh]	13.4	13.5	16.9	16.9	17.2
Upper bound at 2.5%	[€/MWh]	89.3	86.6	93.3	90.1	90.6
Gas CC	[%]	11.4	11.4	25.1	34.1	37.1
Gas CHP	[%]	31.1	31.1	32.8	32.8	32.8
Coal	[%]	29.4	29.7	40.0	18.3	15.3
Nuclear	[%]	1.1	1.1	1.1	1.1	1.1
Renewable wind	[%]	16.8	16.8	0.0	5.0	5.0
Renewable biomass	[%]	8.8	8.8	0.1	7.7	7.7
Renewable other	[%]	1.5	1.1	0.9	0.9	0.9

Table B.4 *Aggregated results SE0, high gas prices*

		Mix P	Mix N high gas	Mix high gas	Mix S high gas	Mix Q
Portfolio cost	[€/MWh]	77.0	81.1	81.1	79.5	73.2
Portfolio risk σ	[€/MWh]	27.0	27.3	33.6	33.6	27.1
Upper bound at 2.5%	[€/MWh]	129.9	134.7	147.0	145.4	126.4
Gas CC	[%]	18.4	18.4	38.6	38.5	18.4
Gas CHP	[%]	37.2	37.2	37.2	38.1	37.2
Coal	[%]	12.1	21.7	21.7	11.6	14.0
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	20.0	16.8	0.0	6.0	20.0
Renewable biomass	[%]	10.5	5.3	1.5	4.7	9.2
Renewable other	[%]	1.7	0.6	1.0	1.1	1.1

Table B.5 *Aggregated results SEp1, high gas prices*

		Mix P	Mix N - SEp1 - high gas	Mix SEp1 high gas	Mix S - SEp1 high gas	Mix Q
Portfolio cost	[€/MWh]	77.0	76.0	76.0	74.5	73.2
Portfolio risk σ	[€/MWh]	27.0	27.0	29.2	29.2	27.1
Upper bound at 2.5%	[€/MWh]	129.9	129.0	133.3	131.8	126.4
Gas CC	[%]	18.4	18.4	24.2	22.6	18.4
Gas CHP	[%]	37.2	37.2	37.4	38.1	37.2
Coal	[%]	12.1	12.2	21.7	21.7	14.0
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	20.0	20.0	14.0	11.6	20.0
Renewable biomass	[%]	10.5	10.5	1.5	4.9	9.2
Renewable other	[%]	1.7	1.6	1.1	1.1	1.1

Table B.6 *Aggregated results SEp2, high gas prices*

		Mix P	Mix N - SEp2 - high gas	Mix SEp2 - high gas	Mix S - SEp2 - high gas	Mix Q
Portfolio cost	[€/MWh]	77.0	75.5	75.5	74.8	73.2
Portfolio risk σ	[€/MWh]	27.0	27.0	29.6	29.6	27.1
Upper bound at 2.5%	[€/MWh]	129.9	128.5	133.5	132.8	126.4
Gas CC	[%]	18.4	18.4	24.2	23.8	18.4
Gas CHP	[%]	37.2	37.2	38.1	38.1	37.2
Coal	[%]	12.1	12.4	21.7	21.7	14.0
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	20.0	20.1	13.4	10.4	20.0
Renewable biomass	[%]	10.5	10.5	1.5	4.9	9.2
Renewable other	[%]	1.7	1.4	1.1	1.1	1.1

Table B.7 *Aggregated results SE0, high biomass prices*

		Mix P	Mix N - SE0	Mix SE0	Mix S - SE0	Mix Q
Portfolio cost	[€/MWh]	61.3	57.9	57.9	56.3	55.8
Portfolio risk σ	[€/MWh]	15.2	15.2	18.9	18.9	16.9
Upper bound at 2.5%	[€/MWh]	91.1	87.7	95.0	93.4	88.9
Gas CC	[%]	18.4	18.4	38.6	41.0	32.0
Gas CHP	[%]	37.2	37.2	37.2	38.1	38.1
Coal	[%]	16.9	17.6	21.7	11.5	4.3
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	20.0	20.0	0.0	4.2	20.0
Renewable biomass	[%]	5.7	5.7	1.5	4.2	4.4
Renewable other	[%]	1.7	1.1	1.0	1.1	1.1

Table B.8 *Aggregated results SEp1, high biomass prices*

		Mix P	Mix N - SEp1	Mix SEp1	Mix S - SEp1	Mix Q
Portfolio cost	[€/MWh]	61.3	57.5	57.5	55.8	55.8
Portfolio risk σ	[€/MWh]	15.2	15.3	16.5	16.5	16.9
Upper bound at 2.5%	[€/MWh]	91.1	87.4	89.9	88.2	88.9
Gas CC	[%]	18.4	18.4	24.2	28.5	32.0
Gas CHP	[%]	37.2	37.2	37.4	38.1	38.1
Coal	[%]	16.9	17.6	21.7	7.8	4.3
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	20.0	20.0	14.0	20.0	20.0
Renewable biomass	[%]	5.7	5.7	1.5	4.4	4.4
Renewable other	[%]	1.7	1.1	1.1	1.1	1.1

Table B.9 *Aggregated results SEp2, high biomass prices*

		Mix P	Mix N - SEp2	Mix SEp2	Mix S - SEp2	Mix Q
Portfolio cost	[€/MWh]	61.3	56.8	56.8	55.8	55.8
Portfolio risk σ	[€/MWh]	15.2	15.3	16.7	16.7	16.9
Upper bound at 2.5%	[€/MWh]	91.1	86.8	89.6	88.6	88.9
Gas CC	[%]	18	18	24	30	32
Gas CHP	[%]	37	37	38	38	38
Coal	[%]	17	18	22	6	4
Nuclear	[%]	0	0	0	0	0
Renewable wind	[%]	20	20	13	20	20
Renewable biomass	[%]	6	5	2	4	4
Renewable other	[%]	2	1	1	1	1

Table B.10 *Aggregated results SEp1, different wind offshore constraints*

		Mix N - 1000 MW	Mix N - 2000 MW	Mix N - 3000 MW	Mix N - 4000 MW	Mix N - 5000 MW	Mix N - SEp1
Portfolio cost	[€/MWh]	57.5	57.5	57.5	57.5	57.5	57.5
Portfolio risk σ	[€/MWh]	16.2	15.9	15.7	15.5	15.3	15.1
Upper bound at 2.5%	[€/MWh]	89.2	88.6	88.2	87.8	87.5	87.0
Gas CC	[%]	19.2	18.4	18.4	18.4	18.4	18.4
Gas CHP	[%]	37.2	37.2	37.2	37.2	37.2	37.2
Coal	[%]	25.2	23.2	20.4	18.0	15.6	12.7
Nuclear	[%]	0.0	0.0	0.0	0.0	0.0	0.0
Renewable wind	[%]	7.8	10.2	12.5	14.9	17.2	20.0
Renewable biomass	[%]	9.5	9.9	10.4	10.5	10.5	10.5
Renewable other	[%]	1.1	1.1	1.1	1.1	1.1	1.1

Appendix C Technology characteristics

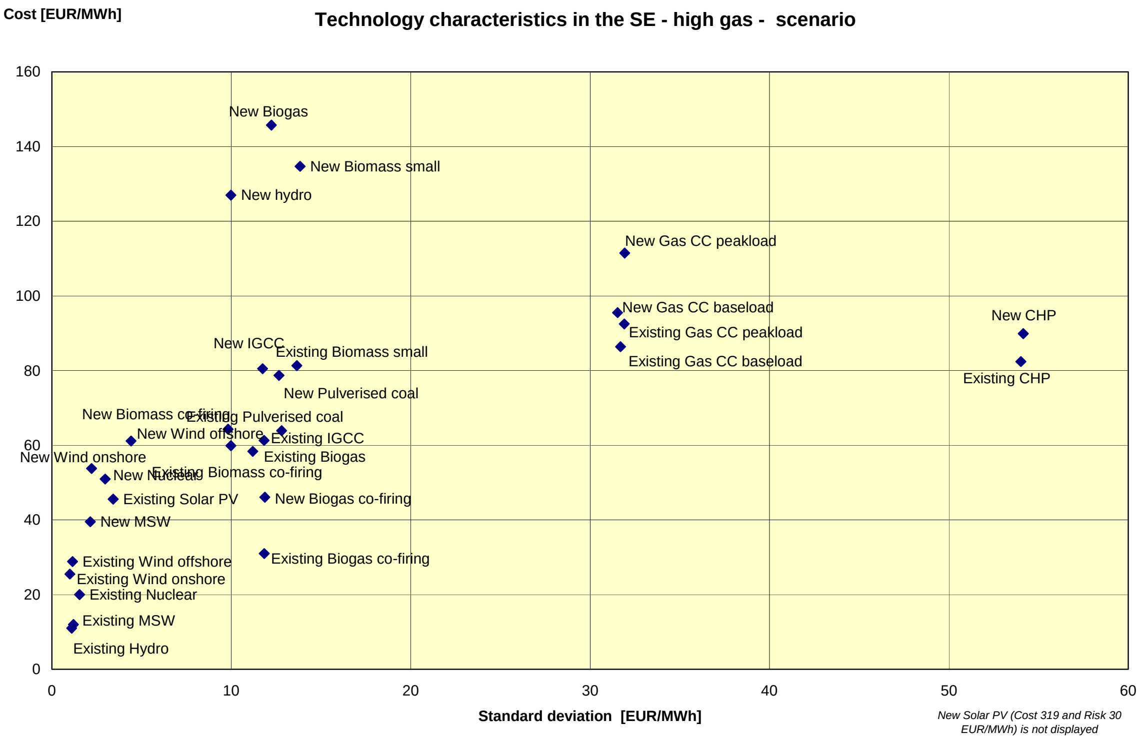

Figure C.1 *Technology characteristics SE (high gas)*

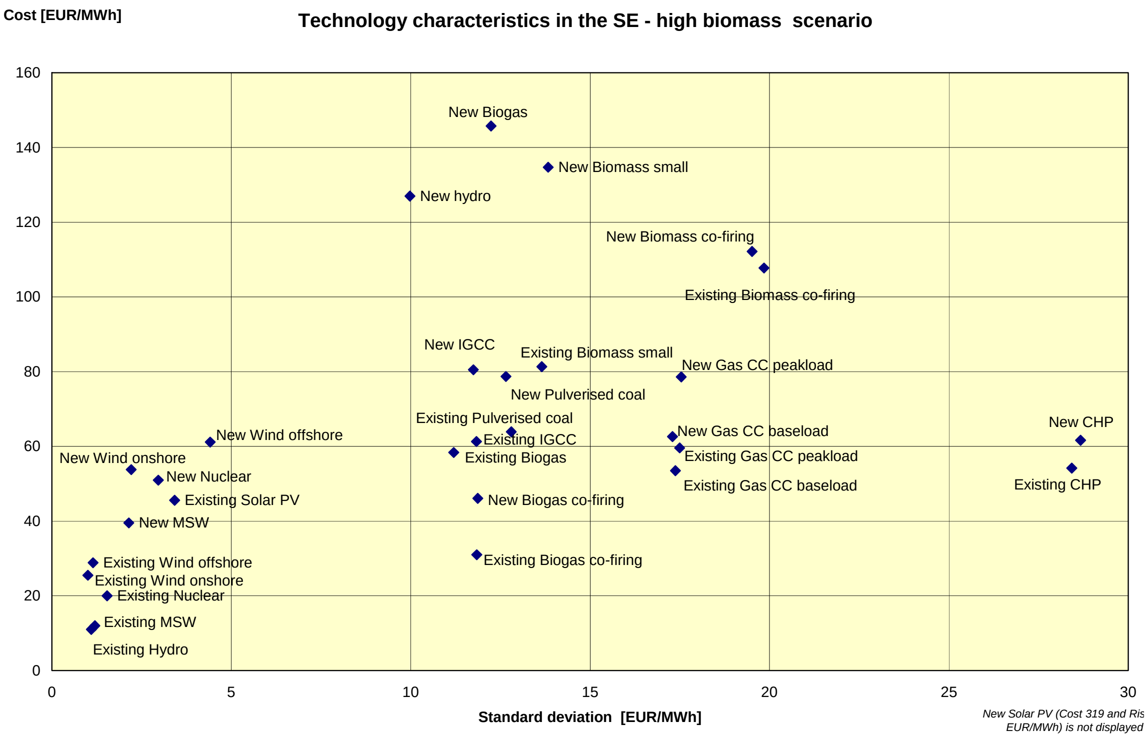

Figure C.2 *Technology characteristics SE (high biomass)*

Appendix D Refinements of the theoretical framework

D.1 Introduction

For a portfolio with two assets, characterised by a certain level of expected HPR and expected risk, the following holds (Bodie, 2002):

$$r_p = w_1 r_1 + w_2 r_2 \tag{D.1}$$

$$\sigma^2 = w_1{}^2\sigma_1{}^2 + w_2{}^2\sigma_2{}^2 + 2w_1 w_2 \rho_{12}\sigma_1\sigma_2 \tag{D.2}$$

Where

$$\rho_{12} = \frac{\mathrm{cov}(r_1, r_2)}{\sigma_1{}^2\sigma_2{}^2} \tag{D.3}$$

$$\mathrm{cov}(r_1, r_2) = \mathrm{E}\left\{\left(r_1 - \mathrm{E}\,(r_1)\right)\cdot\left(r_2 - \mathrm{E}\,(r_2)\right)\right\} \tag{D.4}$$

In the formulas A.1-A.4 above, the following legend applies:

r: expected HPR, a random variable which presumably can be characterised by a probability distribution

w: portfolio weight (with all weights adding up to unity)

σ: risk (standard deviation)

Cov: coefficient of covariance, the extent to which two random variables co-vary; its parameter value is sensitive to the numéraires chosen for either of the two random variables

ρ: coefficient of correlation, the extent to which two random variables co-vary, scaled such that it ranges from -1 (perfectly negative co-variation) through 0 (no relationship) to +1 (perfectly positive co-variation); its parameter value is insensitive to the numéraires chosen for either of the two random variables

p,1,2 indices referring to portfolio, asset 1, and asset 2 respectively

The portfolio risk depends *inter alia* on the co-variation of return on asset 1 and asset 2 respectively:

$$corr(r_1, r_2) = 1 \Rightarrow \sigma_p = w_1\sigma_1 + w_2\sigma_2 \tag{D.5}$$

If the asset returns are perfectly positively correlated, then portfolio risk σ_p equals the weighted average of their standard deviations. If the asset returns are not perfectly positively correlated, then σ_p is *less* than the weighted average of the standard deviations of the individual asset returns:

$$corr(r_1, r_2) = 0 \Rightarrow \sigma_p = \sqrt{w_1{}^2\sigma_1{}^2 + w_2{}^2\sigma_2{}^2} \tag{D.6}$$

$$corr(r_1, r_2) = -1 \Rightarrow \sigma_p = \left|w_1\sigma_1 - w_2\sigma_2\right| \tag{D.7}$$

It can be proven that if the unweighted average covariance among security returns is zero (i.e. all risk is firm-specific), the portfolio standard deviation can be completely diversified away (Bodie et al., 249-250).

The 2-asset case can be generalised into an n-asset case as follows:

$$r_p = \sum_{i=1}^{N} w_i r_i \tag{D.8}$$

$$\sigma_p{}^2 = \sum_{i=1}^{N}\sum_{j=1}^{N} w_i w_j \rho_{ij} \sigma_i \sigma_j \tag{D.9}$$

In matrix notation this boils down to:

$$\sigma_p{}^2 = \sum_{All\ elements} \begin{bmatrix} w_1{}^2\sigma_1{}^2 & w_1 w_2 \rho_{12}\sigma_1\sigma_2 & \cdots & w_1 w_n \rho_{1n}\sigma_1\sigma_n \\ w_2 w_1 \rho_{21}\sigma_2\sigma_1 & w_2{}^2\sigma_2{}^2 & & \\ \vdots & & \ddots & \vdots \\ w_n w_1 \rho_{n1}\sigma_n\sigma_1 & \ldots & & w_n{}^2\sigma_n{}^2 \end{bmatrix} \tag{D.10}$$

$$\sigma_p{}^2 = \iota^T \cdot w \cdot w^T \cdot \sigma \cdot \sigma^T \cdot \mathrm{P} \cdot \iota \tag{D.11}$$

Where:

ι is the unity vector $[1..1]^T$
w is the vector of portfolio weights
σ is the vector of portfolio risks (std dev)
P is the matrix of correlations between any two asset returns

Major outputs of MPT analyses on portfolios of a set of risky assets (not comprising a risk free asset) include:

1. A model calculating portfolio return and risk combinations for varying asset allocations along with the set of minimum risk portfolios at varying returns. Asset allocations are denoted by holding weights, summing up to one.
2. A graph of the '*minimum variance frontier*'. This graph - with risk values on the X-axis and portfolio expected returns on the Y-axis - depicts a set of points, each of which indicates a given portfolio expected return and the minimum standard deviation (c.q. the minimum variance, being the square of the standard deviation) that can be attained for the indicated portfolio expected return. The part of the frontier that lies above the global minimum-variance portfolio is called the *efficient frontier*.
3. A diagram showing the composition of the efficient frontier at a wide range of risk values (e.g. Fabozzi et al.(2002:p.11, exhibit 11)).

These outputs can be generated, based on a simple non-linear optimisation model. For example, for the 2-asset case the model can be formulated as follows (More and Weatherford (2001: 357)):

Minimize:

$w_1{}^2\sigma_1{}^2 + w_2{}^2\sigma_2{}^2 + 2w_1 w_2 \rho_{12}\sigma_1\sigma_2$	variance of portfolio return	(D.12)

Subject to:

$w_1 + w_2 = 1$	allocating all funds
$w_1 r_1 + w_2 r_2 \ge b$	lower bound on the expected portfolio return
$w_1 \le S_1$	upperbound on investment asset 1
$w_2 \le S_2$	upperbound on investment asset 2
$x_1, x_2 \ge 0$	short selling is not allowed

Bodie et al. (2002: 232) explains that only the first two constraints are strictly necessary [18]. In many applications at least the last constraint (short selling not allowed) is also imposed. Various textbooks with accompanying CD-ROMs show how MS Excel spreadsheets can be made and 'Solver' solutions can be generated, e.g. More and Weatherford (2001: 356-362), and Bodie *et al.* (2002: 229-233).

Standard MPT models are widely applied to the selection of optimal financial portfolios (Fabozzi *et al.*, 2002). For forward-looking applications, the fund manager has to make an assessment of:

- For each asset, the expected HPR.
- For each asset, the expected level of risk (expected standard deviation of HPR).
- For each pair of assets, the expected correlation factors between the expected HPRs of each pair of assets.
- If applicable, imposed constraints on the use of specific assets (e.g. maximum portfolio weights).

The requirements with respect to correlation factors can be shown in the diagram below:

Table D.1 *Format of the correlation matrix*

	ρ_{i1}	...	ρ_{ij}	...	ρ_{in}
ρ_{1j}	1	...	ρ_{i1}	...	ρ_{1n}
...	...	...	...	...	...
ρ_{ij}	...	...	1	...	ρ_{in}
...	...	...	...	...	...
ρ_{nj}	...	...	...	...	1

The matrix is symmetric around the diagonal ρ_{11} - ρ_{nn} , while the diagonal elements are equal to unity. This reduces the need for estimates of values of correlation coefficients to ½ n(n-1) elements.

Point of departure for preparing inputs for forward-looking applications is a set of estimated parameter values from historical time series. Applying such a set without adjustments would presume that the past is a good predictor of the future. Yet analysts may wish to alter historical estimates based on expert judgment on current or impending trend changes. Indeed, Fabozzi et al. (2002, p. 11) state that '*If portfolio managers believe that the inputs based on the historical performance of an asset class are not a good reflection of the future expected performance of that asset class, they may objectively or subjectively alter the inputs.*'

Questions have been raised with respect to the appropriateness of the standard deviation as a risk measure of HPR in the case that the probability distribution of HPR is non-Gaussian. This may be the case when its probability distribution is projected to be skewed to the right or, alternatively, skewed to the left. In fact, MPT analysis presumes that the probability distribution of returns can be approximated by normal distributions. In the case of a skewed to the right probability distribution 'bad surprises' are broadly expected to be of limited magnitude while on the other hand low probability events of extremely 'pleasant surprises' are considered possible. Such distributions can be described using third and higher 'central moments', with the expected return and its variance. The major theoretical justification for mean-variance analysis is Samuelson's 'Fundamental Approximation Theorem of Portfolio Analysis in Terms of Means, Variances, and higher Moments'. It proofs *inter alia* that in many important circumstances the importance

[18] Bodie *et al.* in fact set the second constraint in the form of an equality $w_1r_1 + w_2r_2 = b$ Starting out making all weights equal they recommend using Excel Solver. The cell with objective function has to be entered first. Next the cell rang with the decision variables, i.e. weights w_i , and the constraints have to be entered. Finally obtain the optimal solution for $r_p = b$. To obtain other points of the efficient frontier repeat the procedure for other values, sothat the graph can be drawn. All these actions can be done with one push on the button using a macro in Excel (or specialized software).

of all moments beyond the variance is much smaller than that of the expected value and variance. Disregarding moments higher than variance will generally not affect portfolio choice (Bodie et al., 2002:174).

Moreover, it has been reported that data on frequency distributions of rates of return on one-year investment in NYSE-listed stocks do not lend itself to a rejection of the hypothesis that returns are approximately normally distributed. The initially clearly right-skewed distributions for very poorly diversified portfolios tend to become almost symmetrical when the number of different stocks included becomes large. (Bodie et al., 2002:175).

D.2 Awerbuch and Berger 's MPT model

The most profound elaborations of Shimon Awerbuch's MPT approach to deployment portfolios of electricity generating portfolios are made in Berger (2003) and Awerbuch and Berger (2003). Hereafter follows a brief review.

In his PhD thesis Martin Berger expanded Awerbuch's model - in close association with Shimon Awerbuch - up to the capacity limits of Microsoft Excel's Solver to some 12 generating technologies, keeping the essence of the methodology broadly unaltered (Berger, 2003; Awerbuch and Berger, 2003). Fuel cost risk - tacitly equated to fuel price risk - and corresponding cross correlations were obtained from certain historical time series. Lacking detailed project cost information, other risk factors had to be based on certain crude assumptions to be further discussed below.

A second major refinement of Berger (2003) and Awerbuch and Berger (2003) to Awerbuch's previous portfolio work was the addition of three other cost categories to fuel outlays, i.e.

- Construction period costs. Martin Berger (Berger, 2003) refers to the cost associated with ex post variability in the planned construction period, while Shimon Awerbuch in later publications implicitly alludes to total investment costs.
- Variable O&M (operations and maintenance) costs.
- Fixed O&M costs.

In order to express portfolio risk in dimensionless percentage terms, available time series for all cost categories (e.g. US$ct per kWh) were transformed into relative changes, analogous to the HPR concept. [19] Relative changes are obtained by dividing annual cost changes by previous year cost levels. (Berger, 2003) and (Awerbuch and Berger, 2003) apply the following formula:

$$r_t = (EV_t - BV_t) / BV_t \qquad \text{(D.13)}$$

, where[20]

r_t : relative change of a cost category (e.g. fuel price per kWh)
EV_t : ending value
BV_t : beginning value

Per technology, weights are attributed to the four cost categories by projecting total levelized costs and levelized costs per cost category. The cost proportions are attributed to the corresponding cost categories. According to Berger (2003: p.29) each technology can be viewed as a 'sub-portfolio' of four 'sub-assets'. Awerbuch and Berger use the risks (assumed standard de-

[19] Awerbuch and Berger reject to establish risk factors on the basis of fuel prices directly instead of fuel price HPRs. Their main argument is that risks factors directly based on fuel prices are susceptible to the arbitrary choice of price dimension (e.g. $ per barrel of oil versus $ per million cubic feet of gas). Moreover, in MPT applications to portfolios of financial assets risk factors are also expressed in percentage points.

[20] Berger (2003), p.29.

viations of relative changes) of the latter, their mutual correlations and their respective contribution to the (technology-specific) cost of electricity as weights to calculate the overall technology cost risk in accordance with equation (D.2) or rather (D.9). Awerbuch and Berger (2003: p. 27, Table 1-2) loosely refer to their empirically estimated ‘fuel risk’ and ‘fuel risk’ cross correlations as being related to ‘HPRs of fuel cost streams’. No allowance is made for *inter alia* risks associated with energy efficiency developments and volumetric risks associated with market developments and technical failures.

Having obtained overall unit cost per technology and technology cost risk they proceed to determine the efficient frontier, applying equation (D.12) using deployment capacities (MW) as weights. In their graphical presentation of the efficient frontier Awerbuch and Berger show ‘portfolio risk’ (the portfolio ‘SD of annual relative changes’) on the x-axis and reciprocal values of portfolio unit costs (hence kWh/US$ct instead of US$ct/kWh) on the y-axis. The y-coordinate stands for ‘portfolio returns’. All portfolio mixes are expressed in capacity terms (e.g. MW or GW).

Awerbuch and Berger make a set of assumptions on risk rates and correlation factors. Risks associated with fuel costs and one-to-one correlation factors between risks associated with different fuels are based on historical time series, applying the HPR concept to fuel prices. The risk factors associated with the HPR of fuel costs are calculated from time series of relative fuel price changes. The HPR concept yields dimensionless percentage rates.
Values for standard deviations attributed to the following non-fuel cost categories are applied:

- the risk associated with construction period costs,
- the risk associated with fixed O&M costs,
- the risk associated with variable O&M costs.

The risk assumptions used by Awerbuch and Berger are presented in Table D.2. The basis for attribution of risk values to construction period costs (or rather investment costs) is explained as follows. Awerbuch and Berger assert that: ‘*wind, PV, and other modular technologies will by definition exhibit little construction period risk. For these modular technologies the SD for construction period risk is therefore set to zero.*’ (Awerbuch and Berger, 2003: p.41). For lumpy technology additions, Berger assumes construction period cost fluctuates ‘in a manner similar to the historic fluctuations of returns of a broadly diversified market portfolio (whose beta = 1.0)’ (Berger, p.44), i.e. 20%. This rate is applied to all lumpy additions (Berger, p.45). For fixed O&M ‘debt equivalent’ risks were assumed (as reflected by a certain corporate bond volatility index). For variable O&M, Awerbuch and Berger assume ‘systematic covariance’ with economic activity as reflected by the overall market risk of a broadly diversified market portfolio (such as the S&P 500).

Table D.2 *Technology risk assumptions used by Awerbuch and Berger*

[%]	Construction period	Fuel	Variable O&M	Fixed O&M
Coal	20	10.6	20	8.7
Gas	20	7.9	20	8.7
Nuclear	20	11.2	20	8.7
Wind			20	8.7
Hydro			20	8.7
Geothermal			20	8.7
Biomass	20	3.7	20	8.7

Note: Awerbuch and Berger refer to these percentage rates as standard deviations of HPRs.
Source: Berger (2003), Awerbuch and Berger (2003).

The fuel price - also loosely referred to as ‘fuel cost streams’- cross correlations Awerbuch and Berger used, are reproduced in Table D.3. Awerbuch and Berger project correlations between the ‘HPRs’ of fuel cost streams on the basis of historical fuel price series in nominal terms (without ‘cleaning’ them of general price inflation).

Table D.3 *Empirically estimated cross correlations of HPRs of fuel cost streams*

	Gas	Steam coal	Crude oil	Uranium
Gas	-[a]	0.48	0.46	-0.27
Steam coal	0.48	-[a]	0.24	-0.13
Crude oil	0.46	0.24	-[a]	-0.37
Uranium	-0.27	-0.13	-0.37	-[a]

[a] The value 1 indicating perfect correlation would perhaps been more appropriate for the diagonal elements.
Source: Awerbuch and Berger (2003, p.27, p.47).

Furthermore, Awerbuch and Berger assume correlation factors regarding risks associated with non-fuel costs as shown in Table D.4. Correlations of variable O&M HPRs for technology A with the ones for technology B are based on assumed ‘systematic’ covariances. Awerbuch and Berger assume that a general rule is applicable to co-variation patterns regarding the yearly cost streams of a certain cost category for one technology versus those of a certain category for another technology. For different categories they expect a relatively low correlation factor (0.1) and a rather high one (0.7) for the same categories appearing in the diagonal elements of Table C.4.

Table D.4 *Cross-correlations for the cost streams for existing generation assets, assumed by Awerbuch and Berger*

Technology B					
Technology A		Fuel	Variable O&M	Fixed O&M	Construction period
	Fuel	Table 2.3	0.0	0.0	0.0
	Variable O&M	0.0	0.7	0.1	0.1
	Fixed O&M	0.0	0.1	0.7	0.1
	Construction period	0.0	0.1	0.1	0.7

Source: Awerbuch and Berger (2003, p. 41).

D.3 Some conceptual issues

Underscoring the value of the Awerbuch/Berger approach to the application of MPT portfolios of generating mixes underlying an electricity system, hereafter we set out some major conceptual issues it raises. We start out with a discussion of the concept of efficient frontier. Next we review the determination of cost risk associated with the deployment of a specific technology. We conclude with a review of the use of correlation factors among technologies.

The efficient frontiers resulting from applying MPT to portfolios of financial assets depicts in a forward looking way a set of points, each of which corresponding to a particular efficient portfolio. Such an efficient frontier representation brings out two dimensions of underlying efficient portfolios: the projected ‘portfolio return’ in percentage terms per period (y-axis co-ordinate) and ‘portfolio risk’ (x-axis co-ordinate), i.e. the projected standard deviation of ‘portfolio return’, both expressed in the same dimension (% per period). Underlying efficient portfolios are composed of a certain efficient, linear combination of individual financial assets from a certain ‘asset universe’, with their respective shares in the projected portfolio value as weights. The essential feature of an efficient portfolio is that its (projected) portfolio return cannot be improved without at the same time higher portfolio risk exposure. We like to point out that the aforementioned risk concept, as brought out by efficient frontiers of financial portfolios is quite transparent.

We contend that the transparency of Awerbuch and Berger s’ efficient frontiers leaves room for improvement. Their efficient frontiers aim to bring out two dimensions of efficient deployment portfolios of electricity generating technologies: the projected ‘portfolio return’ expressed in energy per monetary unit (e.g. kWh/US$ct) on the y-axis and ‘portfolio risk’ expressed in percentage points on the x-axis. Their labels give rise to, among others, the following issues:

- From a societal point of view, the key concerns with respect to future electricity mix portfolios is the (projected) future cost of electricity (COE) and the (projected) risk surrounding the COE, given proper internalisation of cost of environmental impacts from electricity generation. Awerbuch and Berger set out to transform the basic trade-off between portfolio COE and portfolio COE risk into terms, that closely resemble the ones of MPT analysis of financial portfolios. Yet doing so reduces the meaningfulness and transparency of the resulting parameter values. First, the meaning of ‘portfolio return’ in the Awerbuch and Berger sense is both less clear and less relevant. Secondly, the conversion from portfolio COE to ‘portfolio return’ blurs the link to ‘portfolio risk’. Thirdly, this conversion introduces a certain, variable, margin of error (see Annex F).
- The meaning of ‘portfolio risk’ as used by Awerbuch and Berger is rather opaque. The expansion of the scope of portfolio risk in Berger (2003) and Awerbuch and Berger (2003) by the inclusion of construction period risk’ as well as variable and fixed O&M cost risk marks a major improvement. Yet, it still does not allow for other important risks such as volumetric risk and technology development risk (e.g. related to developments regarding technology cost reduction and technical reliability). Moreover, the transformation from the evolution of COE components as such to relative changes of COE components, prompted among others to more closely emulate the financial HPR concept, complicates the interpretation of the resulting parameter values. Awerbuch and Berger appear to (implicitly) interpret resulting ‘portfolio risk’ values as values for the coefficient of variation (standard deviation divided by the mean of ‘portfolio returns’). If this is the case indeed, we doubt as to whether such an interpretation is theoretically correct. Moreover, a transparent risk parameter has the same dimension(s) as the one(s) of the variable to which that particular risk pertains.
- The non-delivery cost risk of intermittent technologies is clearly underestimated by Awerbuch and Berger. This issue becomes especially significant when intermittent technologies, notably wind power technologies, will gain significant portfolio share. Determination of this risk remains a serious challenge though.
- In order to derive a parameter value for technology-specific COE risk from risk assumptions regarding COE component cost for a certain technology, Awerbuch and Berger use the projected COE component cost as weights. As shown in Annex G hereafter, this procedure is not correct.
- Expressing underlying efficient portfolios in terms of the contribution of the distinct portfolios to the (projected) portfolio capacity (e.g. in MW) without prior correction for divergent technology-specific capacity factors is not correct. We propose to express electricity sector portfolios simply in terms of energy (e.g. GWh or TWh) shares.
- The (ex ante) investment cost risk, surrounding new investments in intermittent technologies is much higher than assumed by Awerbuch and Berger. A systematic framework for risk determination, that not only includes ‘construction period risk’ but e.g. also volumetric risk and technology development risk has to used to arrive at better risk estimates (See Section D.4).

- The use of historical values of broad financial market parameters to estimate the risk of fixed and variable O&M cost components seems far-fetched. For one thing, as projected future electricity costs are in real terms all risk factors should refer to real cost streams. Hence, yearly variations in cost streams should be net (exclusive) of general price inflation. Second, the distinction between variable and fixed O&M is much less clear and subject to specific interpretations in practice than it would appear at first sight. For instance, O&M service contracts do not typically cover the whole economic life of generating plants. Moreover, they will typically contain a number of risk transfer clauses may render the overall cost of periodic O&M services somewhat more volatile than suggested by the term 'fixed O&M'. It is a matter of arbitrary classification how to attribute the variable components of fixed service contracts. We will assume that these cost - which may vary inter alia with the technical maturity of the technology - are attributed to 'variable O&M'. Moreover, variable O&M relates among other things to additives and auxiliary materials such as lubricants that may show rather little variation per unit of electricity generated. Hence, for fixed and - with the exception of less mature technology such as offshore wind - variable O&M we would expect rather limited input volume variability. Real price variability (variability of input prices net of general price inflation) depends on the (to some extent technology-) specific inputs. Perhaps with the exception of variable O&M for offshore wind, the values used by Awerbuch and Berger seem to significantly overstate the risk associated with these cost categories.

For application of MPT a correlation matrix needs to be determined. The efforts of Awerbuch and Berger to that effect denote a brave and bold first attempt, which set the stage for subsequent refinement and improvement. Hereafter we pinpoint some methodological issues at play:

- The empirically estimated fuel risks and pair-wise mutual 'fuel risk' correlations do only reflect to a certain degree, comprehensive fuel cost risk. For example, volume risk due to intermittency and system energy efficiency variation are not included. Moreover, COE component costs are projected *in real terms* (excluding general price inflation), whereas Awerbuch and Berger s' empirical estimates for fuel risks and cross correlations of relative changes in fuel prices are based on unadjusted nominal fuel price trends including general price inflation. It could be argued that this not done either in Markowitz portfolio analyses of financial assets. Yet this argument misses the point, that in this respect the analogy of Awerbuch and Berger's 'HPRs of fuel cost streams' to Markowitz portfolio analyses does not hold. The latter considers HPRs in relative terms indeed (with respect to the overall portfolio value). By contrast, the 'portfolio returns' shown by Awerbuch and Berger on their efficient frontier graphs are reciprocal values of *absolute* portfolio COE values, expressed in a *real terms* monetary unit, for example in US$ct at constant 2000 mid-year prices.
- Correlations of variable O&M 'HPRs' for technology A with the ones for technology B are based on assumed 'systematic' co-variances. Awerbuch and Berger apparently assume that a general rule is applicable to co-variation patterns regarding the yearly cost streams of a certain cost category for one technology versus those of a certain category for another technology. For different categories they expect a relatively low correlation factor (0.1) and a rather high one (0.7) for the same categories appearing in the diagonal elements of Table 2.4. We would expect however, that any such co-variation pattern, if existing, is very dependant on the specific pair of technologies considered. In the absence of specific information on co-variance patterns, the best working assumption would seem to assume that these cost streams are independent from one another.
- A possible exception is comprised by investment cost ('construction period cost') streams of different technologies. Investment costs for most technologies include significant steal, civil works, and (other) labour costs. Yet *ex ante* (before plant construction) most risk relates to technological progress, to differences between planned and realised construction period and to the appropriate *real* discount rate (for one part technology-specific and due to common capital market developments for another part vintage specific). *Ex ante* investment risk is reduced by the spread of vintages among and within technologies. From a societal point of view, it is non-existent for 'old' plants, i.e. plants commissioned before the

end of the base year. *Ex post* (after plant construction) co-variation may also relate to variations in real discount rates, but also importantly to risk regarding annual output volumes and deviations of actual from planned plant life times. The latter would seem quite technology-specific. All in all, some moderate co-variation may hence be expected between annual fluctuations in real investment costs between different technologies, dependent on the expected significance of variations of real discount rates over time.

D.4 Proposed adjustments of the analytical framework

D.4.1 Introduction

In this section an overview is made of proposed adjustments to the analytical framework described by Awerbuch and Berger (2003) and Berger (2003). These adjustments have been proposed and already partially implemented by the authors in the course of a trite of projects on MPT applications to future one-period electricity generating mixes in ongoing research collaboration with Shimon Awerbuch.

Proposed key adjustments concern:

i. Transformation to a risk-cost efficient frontier with energy-based portfolios (see Section 2.4.1);
ii. Design of a transparent, comprehensive concept of portfolio risk and determination of its parameter values. The framework includes preliminary provisions for environmental costs and intermittency costs (see Section D.4.2);
iii. Design of an analysis tool related to incremental technology deployment analysis (see section D.5).

D.4.2 A consistent comprehensive framework for risk assessment

The key feature of the MPT approach to power system optimisation is that not only the expected portfolio cost (COE) is considered. The expected (COE) cost risk is considered to constitute an important second dimension in the optimisation process. To project the comprehensive MWh cost risk, associated with a generating technology, we need assumptions on fuel cost risk and on all other cost components.

Unit technology cost

Unit technology costs are expressed in monetary terms per unit of electricity production. Unit technology costs (UTCO) are broken down into the following cost categories:

INCO - investment cost, annualised: in €/MWh
FUEL - fuel cost: in €/MWh
FIOM - fixed O&M (operation and maintenance) cost: in €/MWh
VAOM - variable O&M costs: in €/MWh
ENAD - environmental adders: in €/MWh

For the time being, decommissioning costs are included in investment costs. Furthermore, a provisional allowance for the additional costs - so-called ‘intermittency cost’- for technologies using intermittent sources is made amounting to € 6/MWh. This assumption is rather conservative (high). Future work has to make a more reliable allowance of the true intermittency costs, which are poised to have a positive relationship with the penetration rate of an intermittent technology.

For a certain technology in a certain year the following holds:

$$UTCO = INCO + FUEL + FIOM + VAOM + ENAD \qquad (D.14)$$

Technology risks

The risk measure, standard deviation of annual COE, used hereafter is to provide an indication for the downside surprises risk (upside cost risk) associated with the corresponding unit cost. *Note that we consider the absolute value of annual costs in real terms and not the relative changes in annual costs ('HPRs') in nominal terms.* Although changes in annual costs and 'HPRs' often tend to be closely correlated, still the respective correlation matrices tend to differ significantly. As we intent to make statements about absolute cost levels in real terms, we opt for a risk measure pertaining to absolute annual cost levels in real terms.

Our goal is derive information on the order of magnitude of COE for specific generating technologies and generating technology portfolios in a certain target year in real terms. Moreover we set out to derive transparent and reliable statements on the order of magnitude of the most unpleasant surprise value at a 2-sided 95% confidence interval of COE parameters in real terms. The probability that portfolio costs will exceed its expected costs plus a margin of twice the standard deviation can be put at 2.5%.

The procedure for projecting the downside risk (upside cost risk) per technology encompasses four steps as follows:

1. For each factor j underlying the expected unit cost of a cost category k, establish the boundary (critical value) α_{jk} of the interval of possible factor values. This value is associated with a 2.5% probability that a more extreme value will occur, with corresponding unfavourable impact on the expected unit costs in the category. Typically, this critical value is based on 'expert judgement'. From this critical value α_{jk} and the expected value, we can deduce the risk σ_{jk} such that $P(X > \alpha_{jk}) \leq 2.5\%$, by dividing the difference between the mean and the critical value by 1.96.
2. For each factor k underlying the expected unit cost of a cost category: establish the downside risk σ_{jk}
3. For each of the five cost categories k: establish the composite downside risk underlying the expected unit cost by applying the following 'rule of the thumb':

$$\sigma_{\mathrm{k}} = \sqrt{\sum_{\mathrm{j}} \sigma_{\mathrm{jk}}^{2}} \tag{D.15}$$

   The foregoing estimator has been established by intuition. It has not been analytically proven. Yet, interestingly, an inductive 'proof' by way of Monte Carlo tests indicates that - under the assumption that the underlying cost factors are mutually statistically independent - the foregoing aggregation operation yields a quite reasonable approximation.
4. Establish the downside risk of a technology as a composite of each downside risk of the five cost categories using the following rule[21]:

$$\sigma = \sqrt{\sum_{k=1}^{5} \sigma_{\mathrm{k}}^{2}} \tag{D.16}$$

   under the premise that all five cost components are mutually statistically independent.[22]

[21] Let X_i be independent and $X_i \sim N(\mu_i, \sigma_i^2)$ and let $W = \Sigma a_i X_i$, then $W \sim N(\Sigma a_i \mu_i + b, \Sigma a_i \sigma_i)$ See Arnold, S. (1990: 172-173).

[22] In the short run, the price of carbon may co-vary positively with the price of gas and negatively with the price of coal (due e.g. to substitution of gas by coal when *ceteris paribus* the price of gas rises). However, *in the long term* fuel cost trends are rather determined by the resource situation and by perceptions of political risks of a concentrated natural gas market, while the carbon price is driven rather by the stringency of climate policy. We consider the assumption of statistical independency a reasonable working hypothesis. Alternatively, an interval estimation instead of a point estimation for technology risk can be made by applying a procedure, proposed by Seitz and Ellison (1995). Shimon Awerbuch suggests recourse to the latter alternative, given the presence so far of a fair amount of ignorance on mutual co-variation patterns between component costs.

This procedure can be formally proven as follows. Given a certain power generating technology with a portfolio of (five) cost components under the premise that the unit cost of each component can be approximated by a normal distribution, the following holds:

$$\mathrm{E}(c) = \sum_{k=1}^{5} w_k \mathrm{E}(c_k) \tag{D.17}$$

$$\sigma^2 = \sum_{k=1}^{5} \sum_{l=1}^{5} w_k w_l \rho_{kl} \sigma_k \sigma_l \tag{D.18}$$

,where:

c_k : the kWh cost of cost component *k* of a certain power generating technology in a target year
w_k : weight of cost component *k* in the total kWh cost of this power technology
c : the total kWh cost of this power generating technology in a target year
σ^2 : the variance of *c*
ρ_{kl} : the correlation coefficient between the unit cost of cost components *k* and *l*

As the total kWh cost of a technology is the, un-weighted, sum of the kWh cost of all cost components, each weight is unity:

$$w_k = 1, \forall k \tag{D.19}$$

Moreover, as by presumption all cost components are mutually independent, it holds that:

$$\rho_{kl} = 0, \forall l, k \neq l \quad \text{,while} \quad \rho_{kl} = 1, \forall\, l,\ k = l \tag{D.20}$$

Hence:

$$\mathrm{E}(c) = \sum_{k=1}^{5} \mathrm{E}(c_k) \tag{D.21}$$

And

$$\sigma = \sqrt{\sum_{k=1}^{5} \sigma_k{}^2} \tag{D.22}$$

The procedure to aggregate COE risk per technology to portfolio risk σ involves one additional step, step 5:

$$c_p = \sum_{i=1}^{N} w_i c_i \tag{D.23}$$

$$\sigma = \sqrt{\sum_{i=1}^{N} \left(X_i \cdot \sigma_i\right)^2} \tag{D.24}$$

Here, X_i is the share of technology *i* in the portfolio mix.

D.5 Incremental technology deployment analysis

During a UNEP/REEEP-organised workshop on portfolio-based power sector planning in Paris, 25 February 2004, Eric Usher of UNEP raised the question whether a tool could be developed for gauging the impact of incremental technology deployment. Point of departure would have to be a certain generating technology deployment portfolio, e.g. a 'target mix'. Jaap Jansen suggested the use of a (sort of) Sharpe ratio, showing the tangent of the direction a certain portfolio at (or to the right of) the efficient frontier would move into by incremental use of a certain technology. Figure 5.1 provides a graphical representation of this suggested tool, which Luuk Beurskens included in the current version of the AIMMS model.[23]

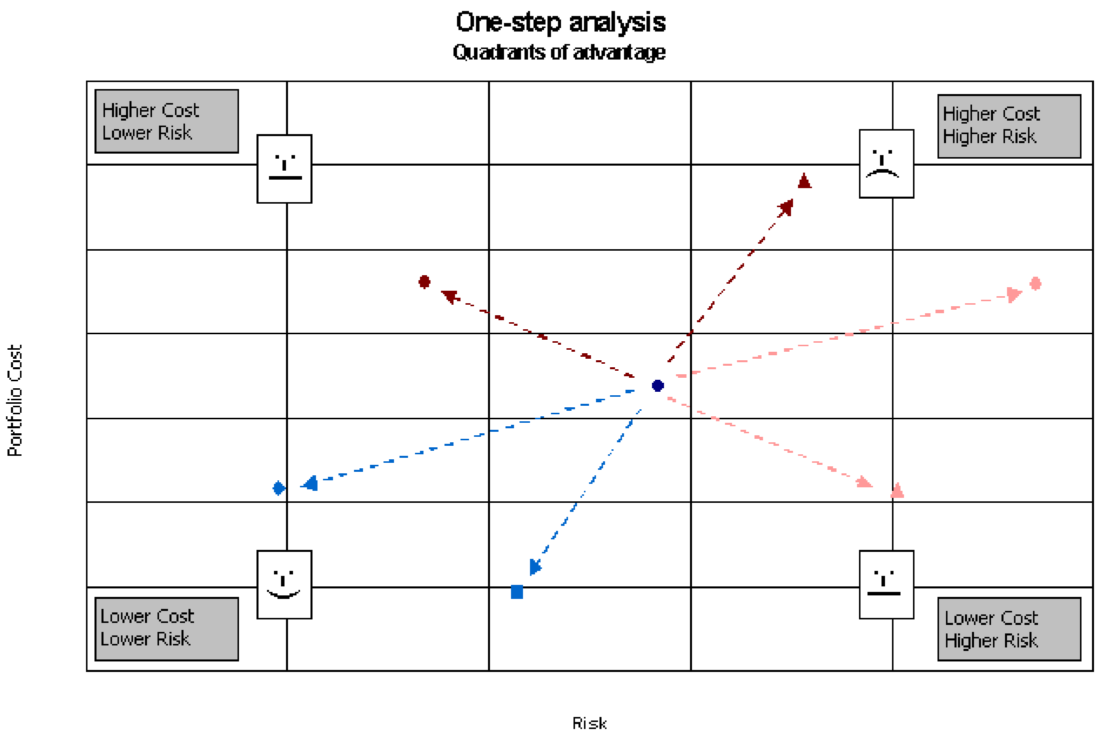

Figure D.1 *Possible risk-cost impacts*

D.6 Summary of findings

In this Annex some recent refinements of - and additions to - the Awerbuch-Berger framework for MPT analysis of generating technology deployment portfolios have been documented. These include:

- Design and implementation of an improved efficient frontier concept;
- A major advance regarding the concept of 'technology risk' and 'portfolio risk'. The procedure for determination of the proposed comprehensive portfolio risk concept encompasses a five-steps procedure. A novel procedure is proposed for aggregating risk of factors for which a multiplicative relationship holds among each other. Although preliminary Monte Carlo simulations indicated that the proposed procedure yields satisfactory approximations, no formal proof of its correctness has been deduced.
- A tool has been introduced for analysis of the impact of incremental deployment of a technology on the performance of a generating technology portfolio.

[23] Shimon Awerbuch will publish on this tool, referred to by him as 'one-step analysis', in a forthcoming article in Kluwer's periodical: *Climate Mitigation and Adaptation*

Appendix E Cost of electricity

In the portfolio planning, analyses are usually made for a single region (say the EU) or country. This analysis may become more realistic when the data that are used are based on statistics from this very region/country. In doing so, the aim is to derive clues on parameter values for the future from realisations in the past.

The analysis focuses on one ore more target years in the medium or (not too distanced) long run, say year 2020 and/or 2030. A target year is a year in future, for which a portfolio of electricity generating technologies has been planned by the competent government agencies under baseline scenario conditions. This future mix is to be compared with the mix in place in the base year, say, year 2005.

Electricity generation and installed capacity

The target mix in electricity generation (TWh) and installed capacity of generating options can be as indicated for some example technologies in the table below.

Table E.1 *Minimum cost and risk portfolios GE0*

Power plant category		Total capacity [MW]		Total generation [TWh]	
		Base year	Target year	Base year	Target year
Coal-fired	old plants				
	new plants				
Oil-fired (Gasoil)	old plants				
	new plants				
Gas Combined Cycle	old plants				
	new plants				
Windpower offshore	old plants				
	new plants				

Note that the distinction between existing plants ('old' plants) and new plants can affect the results. Imagine a future target year, that in part consists of pre-2005 plants, year 2005 being the base year, and on the other hand of plants that have been newly built in the post-2005 period. As pre-2005 plants are already in place, this influences the assumptions on investment risk and investment costs (see further). Taking into acccount the expected decommissioning of 'old' plants, their total installed power and energy production is likely to be smaller in the target year, compared to the base year.

Time series of annual fuel prices

A key risk factor is fuel price risk. Point of departure for setting fuel price risks and correlation factors between distinc fuels are realised values as implied by historical time series. Time series should at least cover a period of 10 years. Historical values for standard deviations of fuel prices is the point of departure for fixing expected fuel price volatility. As the only thing that is certain about the future that everything is uncertain, the analyst can adjust historical values as (s)he deems appropriate.

Investment cost

Investment cost per unit of output is a function of:

- I: total investment cost per unit of capacity (kW) at commissioning date of the generating plant
- The real cost escalation factor, which will be tacitly presumed to be 1 unless there are strong reasons to expect a different factor. This boils down to the assumption that investment cost will change in line with the general rate of inflation
- r: the real cost of capital, which is a function of the real risk free borrowing rate and the technology-specific and region-specific risk premium. The real risk free rate of borrowing can be estimated from the prevailing effective interest rate on government bonds with a high credit rating dominated in the currency chosen by the user and the corresponding rate of inflation. For US$ and € the going *real*[24] risk-free rate is currently around 2% per year. The risk premium for most generating technologies range typically from 4% to 10%. Hence real discount factors used for power generation projects are typically in the range 6%-12%. In the WETO H_2 project a generic real discount rate of 8% is used.
- F: the average full load hours per year
- T: the economic life time, after which the generating plant considered will be scrapped.

The investment cost per unit of output can be determined, aided by the following formula:

$$INCO = (I * 1000 * CRF(r,T)/F)$$

where CRF stands for capital recovery factor.

Fuel costs

The fuel cost per MWh is a function of:
- p_f : the average price of the fuel (€/toe)
- η : the system conversion factor

This cost can be determined by the following formula:

$$FUEL = (p_f * 3.6) / (\eta)$$

Fixed O&M

The average annual fixed O&M cost, FC, are expressed in €/kW.
The fixed O&M cost per MWh is a function of:
- FC: the average annual fixed O&M cost
- The real cost escalation factor, which will be tacitly presumed to be 1 unless there are strong reasons to expect a different factor. This boils down to the assumption that fixed O&M cost will change in line with the general rate of inflation
- F: the average full load hours per year

$$FIOM = (FC * 1000 * F)$$

Variable O&M

The average variable O&M cost, VC, are expressed in €/MWh

$$VAOM = VC$$

For the time being, additional cost for variable out technologies are charged a (rather high to be on the conservative side) 6 € / MWh intermittency premium. In a future more advanced model version the intermittency premium should be made dependent on the penetration level of the technology concerned. For example, the assumed premium might be a reasonable assumption

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[24] That is, after adjustment for (i.e. removing the impact of) inflation. For example, if the unadjusted borrowing rate is 4% and the rate of inflation is 2% then the real borrowing rate is approximately the difference, i.e. 2%.

for wind power at a 20% level, while for lower penetration levels a lower premium would be in order.

Environmental adders

Depending on legislation in place in the host country of a power-generating project, polluting emissions per MWh output will add to generating costs. Hereafter, only allowance is made for CO_2 emissions. However, the method of allowing for other pollutant emissions is basically the same.

The cost of CO_2 emissions per MWh of output depend on:

- $e_{CO2,\ fuel}$: the CO_2 emission factor of the fuel used (tCO_2/GJ fuel)
- p_{CO2} : the price of CO_2 (US$/$tCO_2$)
- η : the system conversion factor

The cost of this environmental adder per MWh can be determined by the following formula:

$$ENAD = (e_{CO2,\ fuel} * p_{CO2} * 3.6) / (\eta)$$

Cost risk per cost component

The procedure applied is explained for investment risk. The procedure for cost risk associated with other components runs similarly.

INCO = f (I, r , T , F)

For each underlying factor the downside critical value at 2.5% rejection level is projected based on expert judgment. For example, for I this is the higher critical value, deemed to be at $2\sigma_I$ from the corresponding expected value. For this critical I value, INCO is determined keeping the other factors at their expected value. This step is repeated for each underlying independent. Finally the overall cost risk associated with INCO is determined as follows:

$$\sigma_{INCO} = SQRT\{\sigma_{INCO(I)}^2 + \sigma_{INCO(r)}^2 + \sigma_{INCO(T)}^2 + \sigma_{INCO(F)}^2\}$$

Monte Carlo analyses performed indicated that the expression above gives a reasonable approximation assuming that the independent variables are statistically unrelated.

Appendix F Minimizing cost vs. maximizing ‘return’

This annex clearly shows that cost minimization may not be treated as, nor is necessarily equivalent to, maximization of return.

In previous work (Awerbuch, Berger) ‘return’ has been used as the basic argument in mean-variance portfolio analysis, closely following the initial applications for optimising portfolios of financial assets. As return was defined as ‘the inverse of the weighted average portfolio cost’ this results in awkward behaviour of the efficient frontier. To illustrate this, consider the example below.

In a two-asset portfolio, the return of various mixes is calculated. For asset 1, the return R_1 is defined as:

$$R_1 = \frac{1}{c_1} \tag{F.25}$$

In which c_1 is the cost of electricity [EUR/kWh] produced by asset 1.

Similarly, for asset 2 the return R_2 is defined as:

$$R_2 = \frac{1}{c_2} \tag{F.26}$$

For evaluating the return of mixes of asset 1 and asset 2 (R_{1-2}), R_1 and R_2 are to be weighted:

$$R_{1-2} = X_1 \cdot R_1 + X_2 \cdot R_2 \tag{F.27}$$

,in which X_1 and X_2 are the respective shares of both assets. Note that whether the share is expressed on a kW or kWh-base is not relevant here.

This can be simplified to:

$$R_{1-2} = \frac{X_1}{c_1} + \frac{X_2}{c_2} \tag{F.28}$$

It is wrong to first calculate the weighted cost, and then to take its reciprocal value, as has been done in the expression below:

$$R_{1-2} = \frac{1}{X_1 \cdot c_1 + X_2 \cdot c_2} \tag{F.29}$$

That Equation (E.30) is not equal to Equation (E.31) (at least, for (X_1,X_2)≠1) is illustrated in Figure F.1.

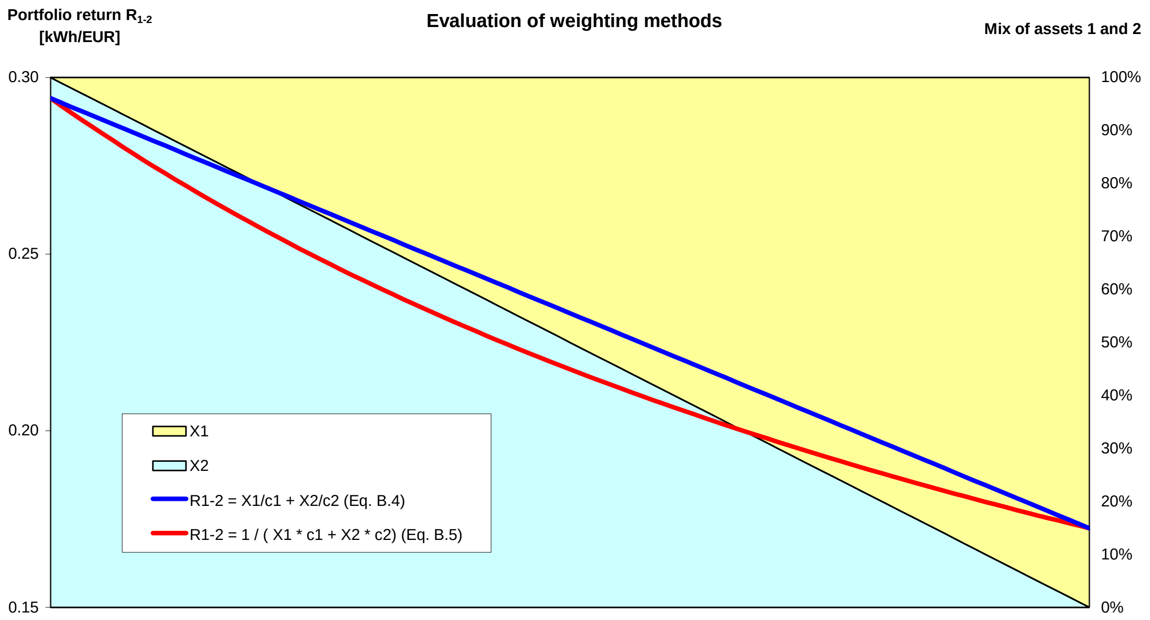

Figure F.1 *Evaluation of weighing*

Appendix G Cost weights in risk assessment

In addition to analytical results, this section illustrates that using weights to calculate technology risk may result in highly inaccurate estimates. Although not stated explicitly, Berger (2003) uses the following common formula for calculating technology related cost risk:

$$\sigma^2 = w_1{}^2\sigma_1{}^2 + w_2{}^2\sigma_2{}^2 + 2w_1w_2\rho_{12}\sigma_1\sigma_2 \qquad \text{(G.30)}$$

Here, w_i is the fraction of cost component *i* in the total, σ_i is the risk of cost component *i,* σ is the total technology risk and ρ_{ij} is the correlation coefficient. To illustrate the effect of using weighted risk, this formula is used to calculate the technology risk for a 'combined cycle gas turbine' (CCGT) generator, based on the values provided by Berger (2003:44-45). The return used here is 0.292 kWh/cent[25] and the technology specific risk - though not stated explicitly- is 7.8%[26].

Assume that ρ only has elements equal to 1.0 at the diagonal and zeros elsewhere (i.e. $\rho_{ij}=\rho_{ji}=0$). The resulting risk is 7.7%, corresponding to value read from the graph by Berger (2003).

Table G.1 *Risk proxies CCGT*

[%]	Investment	Fuel (Gas)	VOM	FOM	Source
Risk proxies	20.0	7.9	20.0	8.7	Berger (2002:Table 5-1)
Weights CCGT	30.4	58.4	4.4	6.9	Berger (2002:Table 5-2)
$W_1{}^2\sigma_1{}^2$	0.37	0.21	0.01	0.00	Calculated

Using the technique presented in this report, simply adding up distinct risks without using weights, leads to a significantly higher risk: total technology risk amounts to 30.6% instead of the 7.7%.

Table G.2 *Risk proxies CCGT*

[%]	Investment	Fuel (Gas)	VOM	FOM	Source
Risk proxies	20.0	7.9	20.0	8.7	Berger (2002:Table 5-1)
Weights CCGT	100.0	100.0	100.0	100.0	N/A, fixed
$W_1{}^2\sigma_1{}^2$	4.00	0.62	4.00	0.76	Calculated

The next example illustrates that using weighted risks can lead to very counterintuitive changes in overall risk. Assume the following cases: two plants with similar technology, one new, and the other existing. Furthermore, assume all parameters equal, except for the investment risk, which is zero for the existing case. When using weighted risks, the difference between the two cases will be directly visible in the weights assigned to the risk components.

Table G.3 *Weighting risks: a new CCGT plant*

[%]	Investment	Fuel	VOM	FOM
Risk proxies	10.0	25.0	5.0	5.0
Weights CCGT	20.0	60.0	15.0	5.0
$W_1{}^2\sigma_1{}^2$	0.04	2.25	0.01	0.00

25 0.292 = 1/3.42, based on Berger 2003, table 5.1.
26 Berger 2003, table 6.2.

Table G.4 *Weighting risks: an existing CCGT plant*

	Investment	Fuel	VOM	FOM
Risk proxies	10.0	25.0	5.0	5.0
Weights CCGT	0.0	75.0	18.8	6.3
$W_1^2\sigma_1^2$	0.00	3.52	0.01	0.00

Calculating risks using the method in Berger (2003) will lead to 18.8% risk for the existing plant and 15.2% risk for the new plant. Based on this method, one must conclude that higher investment risk leads to lower overall risk. In a similar counterintuitive fashion, *increasing* investment cost of the new plant yields a lower risk of 13.9% (vis-à-vis 15.2%) (see table x.x).

Table G.5 *Weighting risks: increasing investment costs*

	Investment	Fuel	VOM	FOM
Risk proxies	10.0	25.0	5.0	5.0
Weights CCGT	27.3	54.5	13.6	4.5
$W_1^2\sigma_1^2$	0.07	1.86	0.00	0.00

Appendix H Energy bounds

Table H.1 *Aggregate overview of technology bounds*

[%]	SE		GE		
	Lower bound	Upper bound	Lower bound	Upper bound	
Gas CC	35.3	96.1	11.4	46.8	[TWh]
Gas CHP	71.3	72.9	31.1	32.8	[TWh]
Coal	0.0	83.3	0.0	55.7	[TWh]
Nuclear	0.0	0.0	1.1	1.1	[TWh]
Renewable wind	0.0	38.4	0.0	16.8	[TWh]
Renewable biomass	0.0	20.1	0.0	8.8	[TWh]
Renewable other	0.0	3.4	0.0	1.5	[TWh]