# The optimal generation mix for an electricity producer: the case of Italy

**Fausto Bonacina**

Supervisor: prof. Silvana Stefani

Dipartimento di Statistica e Metodi Quantitativi

Università degli Studi di Milano-Bicocca

December 2013

## Abstract

In this work we extend the model of Roques et al. (2008) for the construction of the optimal electricity generation portfolio. In our analysis we consider an electricity producer, who can choose to invest both in renewable and conventional sources. We build portfolios based on the Net Present Value generated by the investment in a particular technology. We use Monte Carlo simulations in order to compute the NPV distributions. As an extension to Roques et al. (2008), we consider the presence of incentives for renewable technologies. We apply our model to Italian data.

# Contents

# Highlights

- We illustrate a general model, based on Monte Carlo simulations, for the computation of the Net Present Value generated by an investment in a plant for electricity generation
- We apply this model to compute the optimal generation mix for an electricity producer in Italy. The model is calibrated with Italian data from 2008-2012
- We consider electricity generation from conventional and renewable plants. We introduce incentives for renewable in the analysis
- The results obtained show that, without incentives, conventional technologies dominate the optimal production mix. These results can be useful for the assessment of the actual Italian incentive policy.

# Introduction

The aim of our work is to find a solution to the problem of an electricity producer, who can produce energy through different conventional and renewable sources, and has to choose the optimal portfolio of electricity production. We consider in particular electricity produced from coal and natural gas as conventional sources and electricity from wind, water and sun as renewable sources.

Investment in electricity generation represents one of the most critical and challenging decisions undertaken within the electricity industry. The portfolio of electricity generating plants is a determinant factor of longer-term industry costs. Indeed, generation investments are generally irreversible, capital intensive and long lived. The decision of the electricity producer depends on a multitude of factors that involve a large variety of risks.

We can compare the problem of the selection of the optimal energy portfolio faced by an electricity producer, to the problem faced by a fund manager who has to choose the composition of an equity portfolio. About classical portfolio selection, there is a vast literature, starting from the work of Markowitz [48]. The basis of this theory states that by diversifying a portfolio of assets, the overall risk can be lowered as compared to risks of individual assets.

The application of Markowitz theory in the field of energy selection, belongs to a more recent strand of literature. An early application of this theory to the electricity sector was presented by Bar-Lev and Katz [8]. They analyze the portfolio of fossil fuels of U.S. electric utility industry. Their aim was to determine if utilities had been using resources efficiently. Their findings suggest that utilities held portfolios characterized by high returns, but also high risks.

More recently Awerbuch and Berger ([6] and [5]) followed this approach. They evaluate the potential application of portfolio theory to the development of efficient European Union generating portfolios. In their work, they define return as the inverse of cost (MWh/€) and risk as the standard deviation of returns. Their results show that the existing EU generating portfolio is sub-optimal from a risk-return perspective. Moreover they show that more efficient portfolios could be obtained by adding renewable technologies, which are considered as "risk free" assets, to the portfolio. They consider in particular wind as renewable technology.

Jansen et al. in 2006 [38] apply the same theory to the future portfolio of electricity generating technologies in the Netherlands in year 2030. Their model brings some theoretical refinements to the model developed by Awerbuch and Berger: they introduce the notion of an efficient frontier based on cost instead of return; they use energy based instead of capacity based portfolios; they express risk in terms of costs instead of a percentage rate. Their results are similar to those obtained by Awerbuch and Berger, in fact they show that diversification could lead to a 20% risk reduction with no extra costs and the promotion of renewable energy could greatly decrease portfolio risk.

Other studies that follow the cost based approach are presented in DeLaquil et al. [25], Delarue et al. [26] and Gotham et al. [33]. In particular, the work of Delarue extends the previous model by taking properly into account actual dispatch constraints and energy sources with variable output. The results show that the introduction of wind power can lower the risk on generation cost, although to a smaller level than reported in other studies. Also Bhattacharya and Kojima [13] consider a cost based approach in the evaluation of the optimal electricity generation portfolio in Japan. They show that, based on the portfolio evaluation, Japan could obtain up to 9% of its electricity supply from renewable sources as compared to the current 1,37%. Zhu and Fan [69] apply a cost based approach in order to evaluate China's optimal generation portfolio. They found that the future adjustments of China's planned 2020 generating portfolio can reduce the portfolio cost's risk through diversification, but a price will be paid in term of increased cost. For renewable power generation, they found that it will be necessary a stronger policy support, because of their high generating costs.

Roques et al. [60] and Munoz et al. [53] overcome the cost based approach, by introducing a return based approach, in which the optimal generation portfolio is constructed considering the return instead of cost. This methodology seems, in our opinion, more consistent with the actual setting of a liberalized market, in which it is important to consider also the electricity price risk. Moreover, an approach based on return, instead of costs, is more suitable for our model, in which we consider the point of view of a private investor in the electricity sector, rather than considering the choice of the optimal electricity portfolio from a national perspective.

In particular, Munoz et al. [53] apply portfolio theory to construct the optimal investment portfolio considering only energy produced from renewable sources. They study in particular the Spanish case. The originality of their approach is in the way they define risk and return. They use as return measure the expected Internal Rate of Return (IRR) calculated on the cash flows generated by an investment in a renewable plant, while risk is computed as IRR's standard deviation. In this way they consider not only the risk related to costs, but also the risk related to varying electricity prices.

Roques et al. [60] follow an approach based on the Net Present Value (NPV) of an investment in the electricity sector. They apply their model on the optimal generating portfolio of the UK, by considering three types of conventional energy (gas, coal and nuclear). Their results show that the high degree of correlation between gas and electricity prices reduce gas plant risks, therefore making portfolios dominated by gas more attractive.

Our model extends the previous literature, by considering renewable sources in the analysis. We take into account the risk of production related to renewables (due to variable weather conditions). Moreover we consider the support schemes adopted to promote the electricity production form renewables, and we see how this affects the optimal production mix. We consider also the presence of environmental markets ($CO_2$ allowances).

The optimal generation mix in our model is constructed by considering the NPV generated by the investment in a particular technology. We generated, through Monte Carlo simulations, different scenarios for each risk factor considered in our analysis, in order to estimate the distributions of the NPVs. Based on these distributions we then computed the optimal generation mix. The model is calibrated using Italian data from 2008-2012.

We find that, without incentives, optimal portfolios are dominated by conventional technologies (in particular gas plants). The only renewable technology, which enters the optimal portfolio composition is hydro, which enters in the most risky portfolios. If we consider incentives, also wind and PV enter the portfolios composition. In this case the risk of renewable sources decreases, although they are still riskier than conventional sources.

# Chapter 1

# Methodologies for portfolio selection

In the literature of optimal generation portfolio there are two major methodologies used for portfolio selection. Each methodology is based on a different definition of risk. The most used is the classical Markowitz mean-variance portfolio theory. Furthermore we see the semi-mean absolute deviation model, which brings some advantages over the MV model. In the following section we briefly describe these two methodologies.

## 1.1 Mean-variance portfolio

The mean-variance approach is the most famous approach in portfolio selection. It is based on the work of Markowitz [48] and it shows the importance of diversification in portfolio selection, that lies in the risk-reduction effect of combining two assets that are not perfectly correlated.

This model is based on strong assumptions about investors preference: investor is assumed to be risk-averse, return loving and acting in a perfect rational way. It is also assumed that each class of asset is sufficiently diversified to eliminate non market risk. Moreover, in mean-variance portfolio theory, standard deviation of returns is used as a proxy for risk, which is valid only if asset returns are jointly normally distributed, and this is the main source of criticisms.

Let us consider $n$ assets. The return of a portfolio constructed with this assets is given by:

$$R_p = \sum_{i=1}^{n} x_i R_i \tag{1.1}$$

where $x_1$ is the weight of asset $i$ in the portfolio, and $R_i$ is the return on asset $i$.

The mean-variance selection model can by defined as:

$$\begin{cases} & \min \sigma(R_p) \\ \text{s.t.} & E(R_p) = \sum_{i=1}^{n} E(R_i) x_i \\ & \sum_{i=1}^{n} x_i = 1 \\ & x_i \geq 0 \quad i = 1, \cdots, n \end{cases}$$

where $E(R_p)$ and $E(R_i)$ denote respectively the expected return of portfolio and the expected return of asset $i$, and $\sigma(R_p)$ denotes the portfolio's return standard deviation (i.e. portfolio's risk). The risk of the portfolio can be written as:

$$\sigma(R_p) = \sqrt{\sum_{i=1}^{n} x_i^2 \sigma_i^2 + 2 \sum_{i=1}^{n-1} \sum_{j=i+1}^{n} x_i x_j \sigma_i \sigma_j \rho_{ij}}$$

where $\sigma_i$ is the standard deviation of asset $i$'s return, and $\rho_{ij}$ is the correlation coefficient between the returns on assets $i$ and $j$.

## 1.2 Semi-Mean absolute deviation model

The mean absolute deviation (MAD) model was proposed by Konno and Yamazaki [42] as an alternative to classic mean-variance model. This model presents two main advantages with respect to the mean-variance model: first, it is a linear problem which can be solved more easily than a quadratic one; second, the MAD can be used to solve large-scale problem where a dense covariance matrix occurs, and no particular distribution is needed.

The portfolio rate of return in the MAD model is defined in the same way of the mean-variance model (see equation (1.1)) . The difference between the two models is in the definition of risk. Indeed, in the MAD model, portfolio risk is given as the expected value of the mean absolute deviation between the realization of the portfolio's rate of return and its expected value. This can be formulated as:

$$w_p = E\left[|R_p - E(R_p)|\right]$$

Given this definition, the portfolio optimization problem can be specified as:

$$\begin{cases} \qquad \min w_p \\ \text{s.t.} \quad E(R_p) = \sum_{i=1}^{n} E(R_i)x_i \\ \qquad \sum_{i=1}^{n} x_i = 1 \\ \qquad x_i \geq 0 \quad i = 1, \cdots, n \end{cases}$$

From this problem, a semi-mean absolute deviation (SMAD) model can be derived (see Liu and Qin [46]), where we define risk as the mean absolute deviation of the portfolio's rate of return below the average (we suppose that for an investor only the downside risk is relevant):

$$\begin{cases} \qquad \min E\left[\left|\min\left\{0, R_p - E(R_p)\right\}\right|\right] \\ \text{s.t.} \quad E(R_p) = \sum_{i=1}^{n} E(R_i)x_i \\ \qquad \sum_{i=1}^{n} x_i = 1 \\ \qquad x_i \geq 0 \quad i = 1, \cdots, n \end{cases}$$

## 1.3 Current electricity generation mix in Italy

Actual electricity generation in Italy is still dominated by conventional technology, although the quota of renewable energy has increased rapidly in the last years, thanks mainly to the incentive policy implemented by the Italian government.

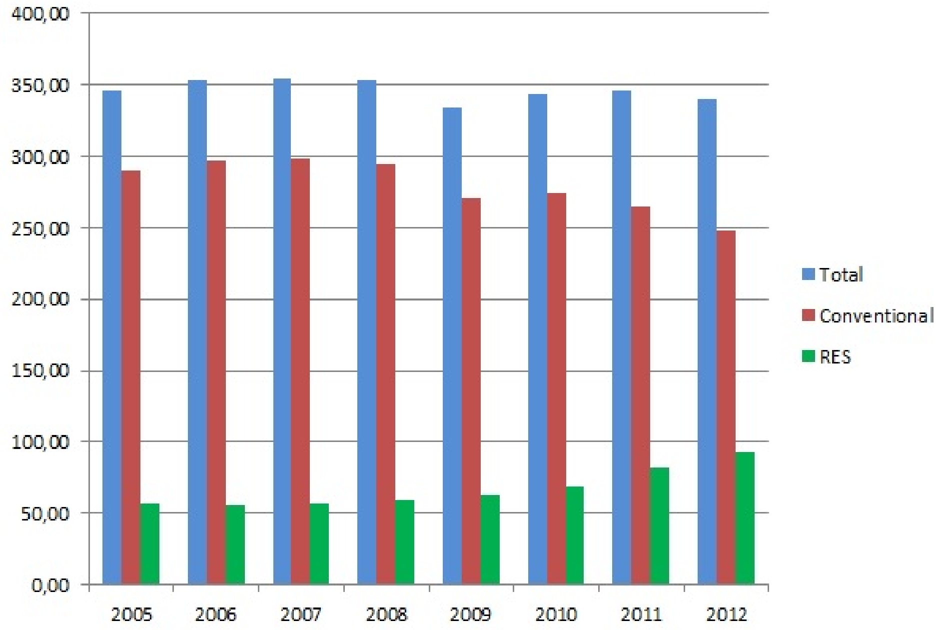


Figure 1.1: Electricity consumption in Italy from 2005 to 2011 (TWh). Source: GSE.

Figure 1.1 shows the composition of the electricity mix in Italy from 2005 to 2011. As we can see, electricity production has been pretty constant form 2005 till 2008, then it slightly decreased in 2009, probably due to the effects of the economic crisis. However the quantity of electricity produced from renewable sources has continually increased. From 2005 to 2012 the quota of electricity produced from RES increased from 16,3% to 27%. Total electricity consumption in 2011 was equal to 346 TWh which is equal to the level reached in 2005.

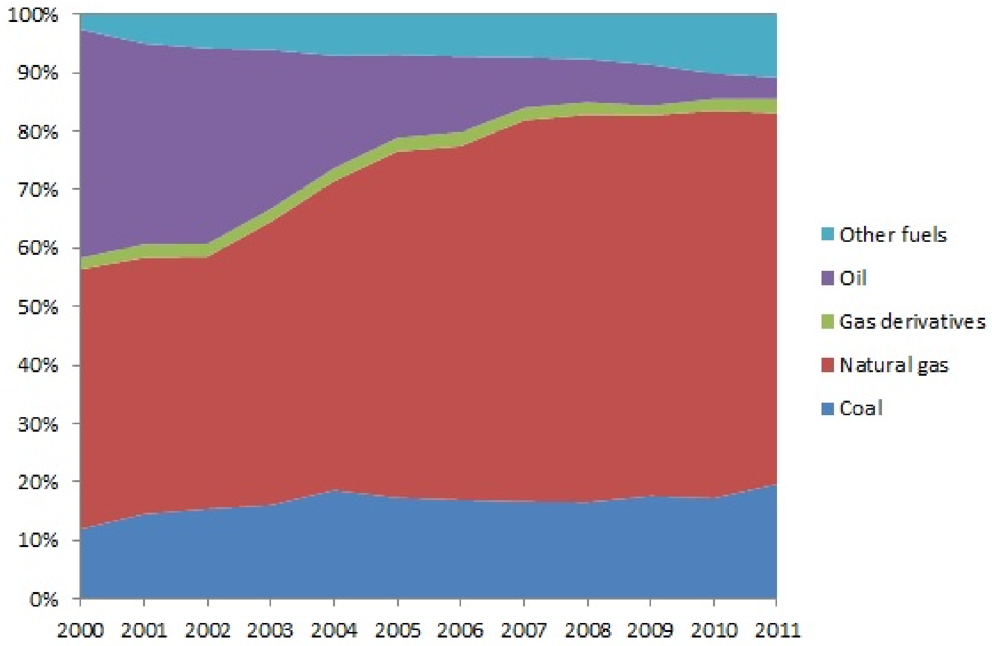


Figure 1.2: Electricity generation from conventional sources in Italy (2000 to 2012). Source: Terna.

If we look in detail at the electricity production from conventional technologies (Figure 1.2), we see that currently almost all conventional electricity is produced from natural gas, which accounts for 59,5% of total thermoelectric production (2012). Other fossil fuels used for electricity production are coal (21,5%), oil (4,3%), which has been gradually substituted by gas, other gas derivatives (about 2,3%) and other solid fuels (about 12,3%). We will consider in our analysis only natural gas and coal plants.

Figure 1.3 shows the detail of the electricity production from RES in Italy.

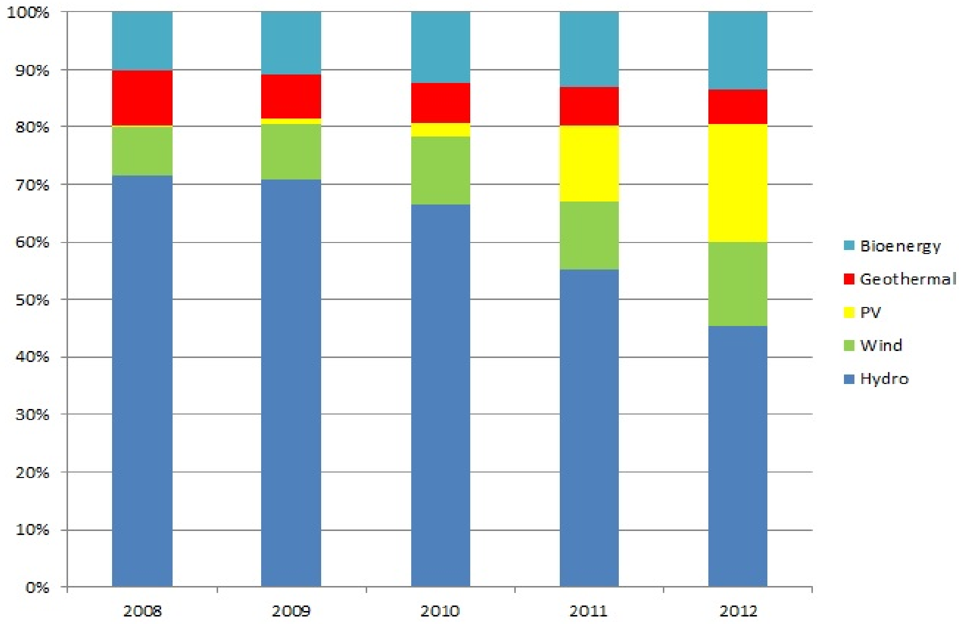


Figure 1.3: Electricity generation from RES in Italy (2008 to 2012). Source: GSE

As we can see the biggest quota of electricity production from RES comes from hydro, but this quota is gradually decreasing. This can be explained by the fact that the potential development of hydro is limited. In fact it has been estimated that the installed capacity of hydro plants could be expanded by 1 to about 5 GW[1] (current installed capacity is equal to 18,2 MW - see table 1.1), so the potential production of electricity from hydro is limited. From Figure 1.3 we can also notice the great expansion of PV and wind. In particular, about PV the installed capacity increased from 0,4 MW in 2008 to 16,4 MW in 2012. The installed capacity of wind has more than doubled, from 3,5 GW in 2008 to 8,1 GW in 2012. This great increase has been possible thanks to the incentive given by the Italian government which

---

[1] See "Rapporto sulle energie rinnovabili", Energy Lab (2011)

favored the electricity sector rather than heating sector. Also bioenergy electricity production increased a lot with an installed capacity more than doubled. In our analysis we will consider in particular electricity produced from wind, sun and hydro.

| **Year** | **2008** | **2008** | **2008** | **2008** | **2008** |
|---|---|---|---|---|---|
| **Hydro** | 17623 | 17721 | 17876 | 18092 | 18232 |
| **Wind** | 3538 | 4898 | 5814 | 6936 | 8119 |
| **PV** | 432 | 1144 | 3470 | 12773 | 16420 |
| **Geothermal** | 711 | 737 | 772 | 772 | 772 |
| **Bioenergy** | 1555 | 2019 | 2352 | 2825 | 3802 |

Table 1.1: Installed capacity of renewable plants in Italy (MW). Source: GSE

# Chapter 2

# The model

Starting from the work of Awerbuch and Berger [6] several approaches have been developed for the construction of the optimal generating portfolio. However, most part of the previous literature applying Mean Variance Portfolio (MVP) theory in order to identify optimal generating portfolio, has focused on regulated utilities or considered a national perspective. Therefore the focus of these studies has been on the production costs of different technologies. In these studies return was defined as the reciprocal of unit generating costs, so it was expressed in terms of kWh/€, and risk was expressed in term of the volatility per holding period (one year).

Here we consider the perspective of an electricity producer in a liberalized market. Private investors cannot be expected to select between different generating technologies only by comparing their production costs. Their evaluation should be based instead on the return and the risk related to the investment (see [34]). In particular, the investor in electricity sector faces a large set of risks which include (IEA, 2005):

- Economic factors that affect the demand for electricity and the availability of labour and capital
- Risks related to the decisions of policy makers, such as regulatory or political risks
- Risks related to operating and construction costs
- Risks related to varying electricity output (for renewable technologies)
- Price and volume risks in the electricity market
- Fuel price risk
- Financial risks that could arise from the financing of investment.

We consider here in particular risks related to fuel costs and electricity price and risks related to electricity output (for renewable technologies). In order to evaluate return on an investment, several approaches can be followed. Munoz et al. [53] consider Internal Rate of Return as a measure of return, while Roques at al. [60] consider the Net Present Value of the investment. We follow here an approach based on NPV.

In our study we consider both energy produced from conventional sources and energy produced from renewable sources. In particular we suppose that the energy producer can produce energy from five different type of sources: gas and coal as conventional sources and sun, wind and hydro as renewable sources.

In order to construct the optimal generating portfolio, we have first of all to estimate the distribution of the NPV of each plant considered in our analysis. The NPV depends on the cash flow generated by each plant, which depends on the streams of costs and revenues. Revenues for all considered technologies vary with electricity prices, while costs depend mainly on fuel costs. Furthermore, we suppose that investment costs and operation and maintenance costs (O&M) are fixed for each plant. So the stream of costs for a renewable plant is fixed for the entire life of the plant, while the stream of costs related to a conventional plant varies as fuel costs vary. Electricity and fuel cost are obtained through Monte Carlo simulations, in which we suppose that each variable is normally distributed with a given mean and a given standard deviation, which are obtained from historical series of electricity and fuel prices. We simulate 100.000 different trajectories for each risk source. By supposing a normal distribution for fuel and electricity cost we get NPVs that are also normally distributed, which is fundamental when we apply mean-variance portfolio.

So our portfolio is obtained with these different steps:

- We collect for each plant data about technical parameters including all capital costs
- We estimate mean, variance and cross correlation for the variables in our model (electricity price, fuel costs and $CO_2$ costs)
- We run Monte Carlo simulations to simulate the level of the variables considered

- On the basis of the results obtained in the previous step we compute the NPV distribution for each plant. We compute in particular the mean, the standard deviation and the cross correlation between the NPVs of each plant
- Finally, we compute the optimal generating portfolio based on NPVs

## 2.1 Model inputs

### 2.1.1 Technical parameters and plant costs

For our analysis we needed to retrieve data for five different generation technologies. We consider the case of Italy. Concerning conventional technologies, we assumed that costs and technical parameters for these plants are broadly similar anywhere in the world (see Keay [40]) . What changes in this case is the price of fuel. For renewable technologies instead, costs and other technical parameters vary a lot across nations. In fact for a renewable plant, geographical localization is an important factor that affects the quantity of energy that can be produced, so affecting the NPV (see [59] and [63]).

The data for coal and gas plant were obtained from a report of the Electric Power Research Institute (EPRI) which contains projected costs for new plants in 2015. We considered in particular the costs for a pulverized coal (PC) plant, which provides nearly all of coal-fired capacity in the US. For gas-fired plants, we considered a Natural Gas Combined Cycle (NGCC) plant, which accounts for almost all electricity generated in Italy.

For renewable technologies we used data from a report of 2011 on renewable energy in Italy [2]. The data are obtained from Politecnico of Milan. The data for the capacity factors for renewable plants are obtained from GSE (see [1]).

Table 2.1 reports a summary of the technical and cost parameters used in our analysis.

| | Unit | NGCC | Coal (PC) | Wind (onshore) | Wind (offshore) | Hydro | PV |
|---|---|---|---|---|---|---|---|
| Net Capacity | MW | 1000 | 1000 | 3 | 3 | 10 | 2 |
| Average Capacity Factor | | 0,85 | 0,85 | 0,17 | 0,34 | 0,29 | 0,11 |
| Average Yearly Production | MWh | 7446000 | 7446000 | 4480 | 9000 | 25640 | 1950 |
| Heat Rate | BTU/kWh | 6900 | 8750 | | | | |
| Carbon Intensity | kgC/mmBTU | 53,55 | 98,29 | | | | |
| Carbon Produced | tC | 2751260 | 6403560 | | | | |
| Construction Period | years | 3 | 4 | 1 | 1 | 1 | 1 |
| Plant Life | years | 30 | 40 | 30 | 30 | 40 | 20 |
| Overnight Costs | €/kWh | 833,5 | 1621,8 | 1375 | 2750 | 2250 | 3100 |
| Fixed O&M | €/KW/year | 12,07 | 36,21 | | | | |
| Variable O&M | €/MWh | 1,73 | 1,5 | 22,5 | 33 | 26 | 22,5 |
| Marginal Corporate Tax | | 0,35 | 0,35 | 0,35 | 0,35 | 0,35 | 0,35 |

Table 2.1: Plant costs and technical parameters

The net capacity represents the maximum quantity of energy produced, when the plant works with full efficiency. The carbon intensity is the quantity of $CO_2$ produced for each unit of fuel. For the costs of conventional plants (gas and coal), costs are converted from dollars to euros (exchange rate $1,3257$). Since we didn't have data about the construction periods of the renewable plants, we suppose a construction period of one year for each plant. Overnight costs[1] for the renewable plant are computed as the average between maximum and minimum overnight cost. Finally, concerning renewable technologies, we suppose that the data on variable O&M[2] costs reported in the table, includes both fixed and variable costs, since in the data we collected we don't have a split between variable and fixed O&M costs.

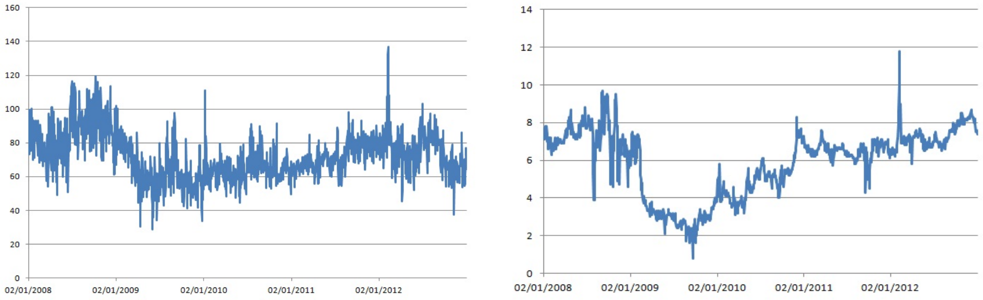
---

[1] Overnight costs represent the initial installation cost of the plant.

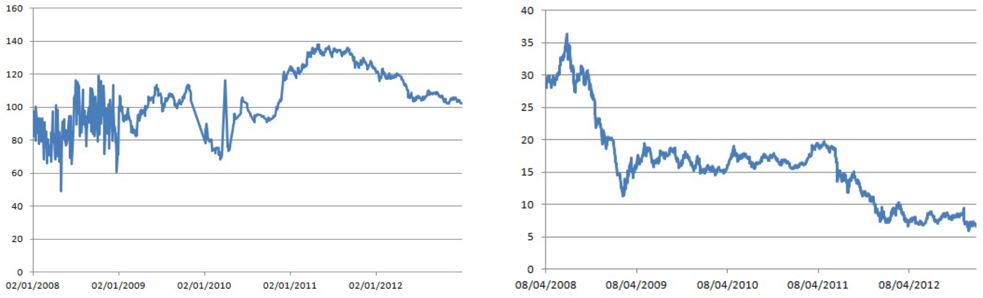
[2] Operation and Maintenance

### 2.1.2 Fuel, electricity and $CO_2$ costs in Italy

In addition to the plant specific investment costs shown in the previous section, we needed to estimate fuel, electricity and $CO_2$ costs, in order to compute the net present value of the investment in each specific plant. We needed in particular gas prices, coal prices, electricity prices and emission certificate prices. We considered data for Italy in the period from 2008 to 2012. We used different sources for each different data. In particular, data for electricity prices were obtained from the Bloomberg database. The source for gas prices was the Ministero dello Sviluppo Economico (MSE). Coal prices and $CO_2$ prices were retrieved from European Energy Exchange (EEX) website.



(a) Electricity prices (€/MWh) (b) Gas prices (€/mmBTU)



(c) Coal prices (€/mmBTU) (d) $CO_2$ prices (€/t$CO_2$

Figure 2.1: Evolution of electricity, gas, coal and $CO_2$ spot prices in Italy. Daily prices. (2008-2012)

Figure 2.1 shows times series of daily base-load and on peak electricity prices, daily gas prices, coal prices and EUA[3] prices from January 2008 to December 2012. Figure 2.2 shows the correlation between average electricity prices and gas prices. As we can see there is a strong correlation between the two variables.

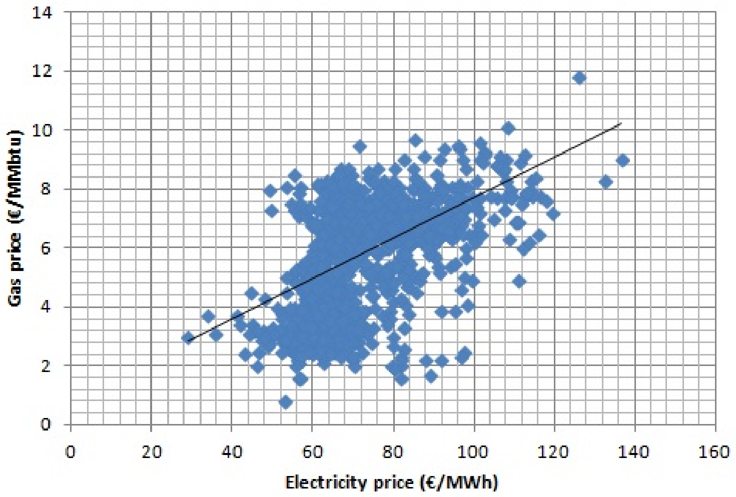


Figure 2.2: Correlation between average electricity pricies and gas prices in Italy

Based on these time series we estimated for each variable the mean, the standard deviation and the cross correlations among all variables. We computed the correlation along the whole period considered (2008-2012). Table 2.2 reports the results for the mean and the standard deviation. Table 2.3 reports the correlation coefficients among the variables.

From this table, we can get a confirmation of the strong correlation between electricity and natural gas, and we see also a quite strong correlation

---

[3] EUA stands for European Union Allowances, which represent the permit to produce one tonne of $CO_2$

|  | Unit | Mean | St. Deviation |
|---|---|---|---|
| **Electricity (average)** | €/MWh | 72,56 | 9,27 |
| **Electricity (peak load)** | €/MWh | 82,81 | 12,09 |
| **Natural gas** | €/mmBTU | 5,75 | 0,81 |
| **Coal** | €/mmBTU | 3,51 | 0,47 |
| **EUA** | €/t$CO_2$ | 14,17 | 5,25 |

Table 2.2: Mean and standard deviation

between electricity and coal. Coal and natural gas seem instead to be almost uncorrelated. We can also notice that the correlation between the electricity and fuel prices is stronger when we consider average electricity price. Considering $CO_2$ allowances, we see that they are negatively correlated with natural gas prices, while they have positive correlation with all other variables.

|  | **Electricity (average)** | **Electricity (peak)** | **Natural gas** | **Coal** | **EUA** |
|---|---|---|---|---|---|
| **Electricity (average)** | 1 | 0,936 | 0,638 | 0,517 | 0,381 |
| **Electricity (peak)** | 0,936 | 1 | 0,513 | 0,352 | 0,608 |
| **Natural gas** | 0,638 | 0,513 | 1 | -0,008 | -0,261 |
| **Coal** | 0,517 | 0,352 | -0,008 | 1 | 0,218 |
| **EUA** | 0,381 | 0,608 | -0,261 | 0,218 | 1 |

Table 2.3: Correlation matrix

### 2.1.3 Capacity factors for renewable plants

Capacity factors are one of the most important parameter affecting the revenues (and so the NPV) generated by a renewable plant. The capacity factor is an indicator of the actual energy produced by a generation plant. It is defined as the number of working hours in a year divided by the total number of hours (which is 8760). In a conventional plant, the capacity factor is generally more stable, in fact the plant can produce electricity almost always and the only cases in which the plant is off is when the cost of producing electricity is higher than the price of electricity (this is the so called spark-spread option). For a renewable plant instead, the availability of the plant depends on weather conditions and so its capacity factor is more variable during time. For this reasons we suppose in our model that the capacity factor for a conventional plant is fixed, while the capacity factor for renewable plants is a random variable. Capacity factors depend also on the geographical localization of the plant. However, here we consider the national average.

We estimated mean and standard deviations for the capacity factors of renewable plants, using the data from 2008 to 2012 of the actual quantity of electricity produced from renewable sources in Italy. Data come from GSE website. Table 2.4 shows the results of these estimations.

| | **Wind (on shore)** | **Wind (off shore)** | **Hydro** | **PV** |
|---|---|---|---|---|
| **Mean** | 0,171 | 0,342 | 0,293 | 0,111 |
| **St. Deviation** | 0,014 | 0,028 | 0,025 | 0,022 |

Table 2.4: Mean and standard deviation of capacity factors. Source: GSE

## 2.2 Estimation of the Net Present Values

We now compute, for each generation plant considered, the distribution of the NPV, based on the data from the previous section. In order to compute the NPV, we need to estimate the cash flow generated from the investment in the generation plant. This cash flow depends of course on the streams of costs and revenues generated by the plant, which are estimated considering the fixed and the variable parameters. We suppose in particular that electricity prices, fuel prices and $CO_2$ prices are jointly normally distributed with mean, standard deviation and covariances given by the estimation presented in the previous section. Finally, to compute the distribution of the NPVs we run a Monte Carlo simulation, in which we constructed 100.000 different scenarios for the NPV of each plant.

### 2.2.1 The economic model for the cash flows

This section shows the calculations used to establish the future cash flows that are the essential input to compute the NPV for each technology. We refer to the model in Munoz et al. (2009). For each technology we need to compute yearly revenue, yearly costs and then we can compute yearly cash flows.

*Revenues*

To compute revenue we need to know the quantity of energy produced, which depends on the capacity factor of the plant, and the price of electricity, which is a variable parameter and is obtained through the Monte Carlo simulations. Yearly revenue for plant $j$ in year $t$ is given by this simple formula:

$$\text{revenue}_{jt} = \text{prod}_{jt} \times \text{electricity}_{jt}$$

where

$$\text{prod}_{jt} = \text{Net Capacity}_j \times \text{Capacity Factor}_{jt} \times 8760$$

and

$$\text{electricity}_{jt} = \text{electricity price}_{jt} \times (1 + \text{inflation})^t$$

We suppose that capacity factors for conventional technologies are fixed, while capacity factors for renewable plants are independent normally distributed random variables, with mean and standard deviations given by data computed in the previous section. We suppose that each plant starts generating revenues after the construction period specified in the technical parameters. For example, a NGCC plant will start generating revenues from the fourth year after the beginning of construction. Electricity price is supposed to be the same for all technologies with the exception of PV. We suppose indeed that a PV plant works only in the day hours, so the owner of a PV plant will sell electricity at the peak load price, a price different from the average electricity price.

*Costs*

To compute costs we have to take into account different cost components. We have to consider annual installation costs, which are given by interests paid on loan and the depreciation of the installation, the annual operation and maintenance costs and, for conventional plants, the cost of fuel and $CO_2$.

As we said in the previous section, operation and maintenance costs can be split in fixed and variable costs. The fixed component depends only on the installed capacity of the plant, while the variable component depends on the electricity actually produced. Operation and maintenance costs are computed according to the following formulas:

$$\text{O\&M Costs}_{jt} = \text{Fixed O\&M}_{jt} + \text{Variable O\&M}_{jt}$$

where

$$\text{Fixed O\&M}_{jt} = \text{Net Capacity}_j \times \text{Fixed O\&M}_j \times (1 + \text{inflation})^t$$

and

$$\text{Variable O\&M}_{jt} = \text{prod}_{jt} \times \text{Variable O\&M}_j \times (1 + \text{inflation})^t$$

The second component of total costs is given by annual installation costs. We suppose that the electricity producer can receive a loan on the entire installation cost and for a period equal to the full plant life. The producer has to pay a fixed interest rate on this loan. So we have:

$$\text{installment}_{jt} = \text{Installation Cost}_j \frac{i}{(1-(1+i)^{-n_j})}$$

$$\text{outstanding}_{jt} = \text{outstanding}_{j(t-1)} - \text{amortised}_{jt}$$

$$\text{interest}_{jt} = i \times \text{outstanding}_{j(t-1)}$$

$$\text{amortised}_{jt} = \text{installment}_{jt)} - \text{interest}_{jt}$$

where $i$ is the fixed interest rate, $n_j$ is the plant life of plant $j$ and the initial outstanding is equal to the installation costs, which are computed as:

$$\text{Installation Cost}_j = \text{Net Capacity}_j \times \text{Overnight Costs}_j$$

In order to have total annual installation costs, we have to add the component given by the depreciation of installation which is computed as:

$$\text{amortization}_{jt} = \frac{\text{Installation Cost}_j}{n_j}$$

The last component of costs is given, only in the case of a conventional plant, by fuel and $CO_2$ costs.

Fuel costs is given by:

$$\text{fuel}_{jt} = \frac{\text{prod}_{jt} \times \text{Heat Rate}_j}{1000} \text{fuel cost}_{jt} \times (1 + \text{inflation})^t$$

Carbon cost is given by:

$$\text{carbon}_{jt} = \text{Carbon produced}_{jt} \times \text{carbon cost}_t \times (1 + \text{inflation})^t$$

where

$$\text{Carbon produced}_{jt} = \frac{\text{Carbon Intensity}_j \times \text{Heat Rate}_j}{1000000} \times \text{prod}_{jt}$$

Putting togheter we have:

$$\text{Total costs}_{jt} = \text{O\&M Costs}_{jt} + \text{interest}_{jt} + \text{amortization}_{jt} + \text{fuel}_{jt} + \text{carbon}_{jt}$$

We suppose that annual installation costs are paid from the beginning of the construction of the plant, while all other type of costs are paid only when the plant comes into operation, so only at the end of the construction period.

*Cash flows*

Before calculating yearly cash flows,we need to calculate corporate tax, which is due on earnings before tax (EBT):

$$\text{EBT}_{jt} = \text{revenue}_{jt} - \text{Total costs}_{jt}$$

$$\text{corporate tax}_{jt} = \text{EBT}_{jt} \times \text{Marginal corporate tax}$$

Finally, we can compute yearly cash flow:

$$\mathrm{CF}_{jt} = \mathrm{EBT}_{jt} - \text{corporate tax}_{jt} + \text{amortization}_{jt} - \text{amortised}_{jt}$$

From yearly cash flow we can compute the Net Present Value as the sum of all present values of the cash flows generated by the plant:

$$\mathrm{NPV}_j = \sum_{t=0}^{n_j} \frac{\mathrm{CF}_{jt}}{(1+r)^t}$$

where $r$ is the interest rate used for the evaluation. We suppose that yearly cash flow is received at the end of each period (we consider it as a ordinary annuity). However, the above formula does not take into account the different net capacities and the different capacity factors of the plants and so does not consider properly the actual dispatch of electricity, so we have to do a normalization of the NPV, by dividing it by the electricity production. We have (in €/MWh):

$$\text{Normalized NPV}_j = \frac{\mathrm{NPV}_j}{\sum_{t=0}^{n_j} \mathrm{prod}_{jt}(1+r)^{-t}}$$

### 2.2.2 Results of Monte Carlo simulations

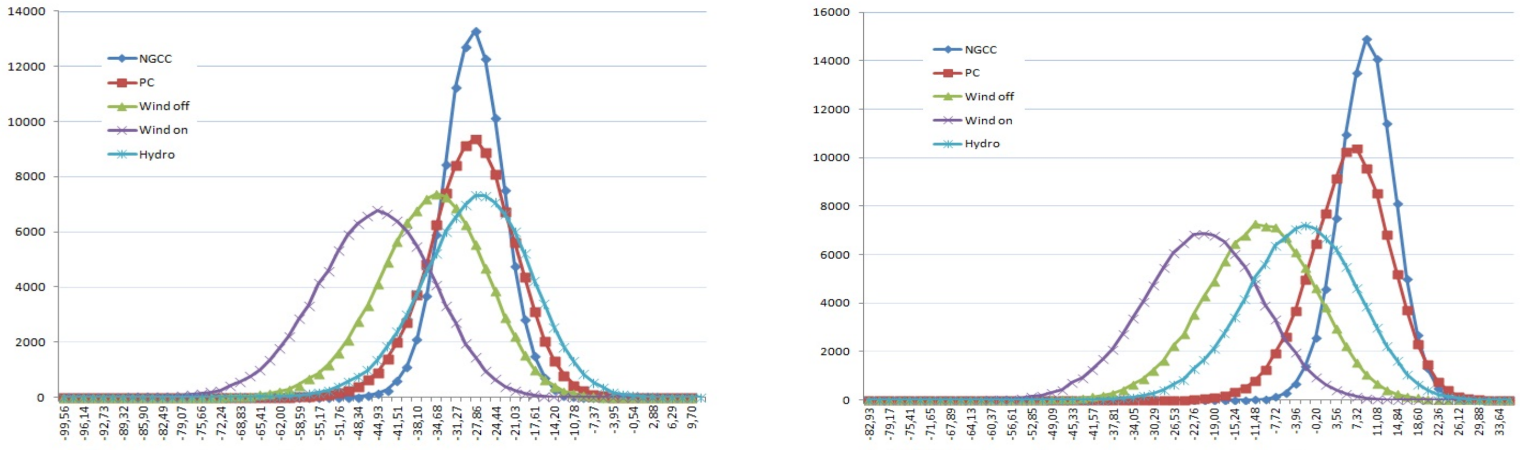
We simulated the Net Present Value of an investment for four different values of the interest rate used for the evaluation. For the simulations we supposed that electricity prices, fuel prices and $CO_2$ prices are jointly normally distributed, with mean, standard deviation and cross correlation given by the estimations made in the previous section. Capacity factors for renewable plants are supposed to be independent normal random variables. We report below the results of the simulations.

Figure 2.3 shows the distribution of the NPVs of each generation plant (excluding PV), for different interest rates. We show PV in another figure (Figure 2.4) because of the different scale of the NPV distribution.

As we can see from these figures, the shape of the NVP distributions doesn't change much as the interest rate changes. Moreover we can notice that the NGCC seems the less risky technology, in fact the other technology have a much more spread distribution.

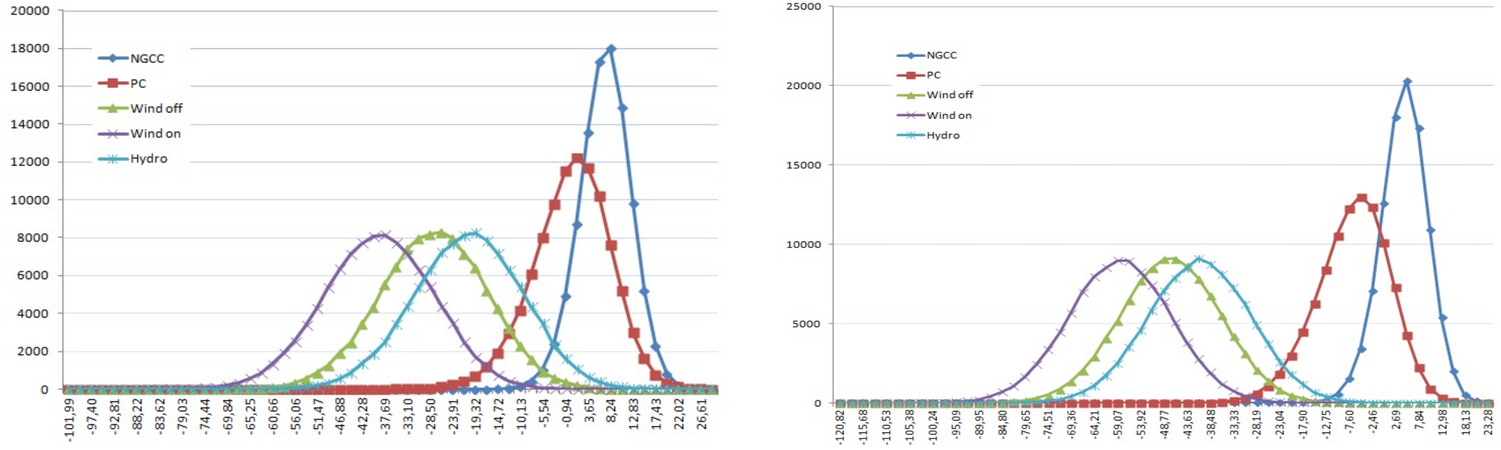
In general as the evaluation rate increases, the NPVs of the plants obviously decrease. This effect seems more relevant for renewable technologies. If we look in detail at the statistics of the distributions (Table 2.5), we see that the NGCC is the only generation technology that has a positive return even with an interest rate of 10%. If we consider only renewable plant, we see that, with the exception of hydro and onshore wind (only when interest rate is equal to 4%), they all have negative returns. It is clear that, in order to be competitive with conventional technologies, they need some kind of support.

Table 2.6 shows the correlations between the NPVs. The main aspect we can notice is that the interest rate used for the evaluation doesn't affect much the correlations, which is almost the same in the four cases.



(a) r=0,04

(b) r=0,06



(c) r=0,08

(d) r=0,1

Figure 2.3: NPVs distributions with different interest rates

(a) Mean of NPVs

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| r=4% | 10,949 | 10,605 | 3,625 | -6,312 | 11,352 | -195,113 |
| r=6% | 9,221 | 5,989 | -10,668 | -21,405 | -3,111 | -245,315 |
| r=8% | 7,14 | 0,273 | -27,866 | -38,995 | -20,8 | -300,811 |
| r=10% | 4,642 | -6,717 | -47,334 | -58,577 | -40,853 | -361,557 |

(b) Standard deviation of NPVs

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| r=4% | 5,164 | 7,569 | 9,322 | 10,092 | 9,365 | 17,91 |
| r=6% | 5,129 | 7,602 | 10,277 | 10,802 | 10,348 | 19,945 |
| r=8% | 5,137 | 7,78 | 10,897 | 11,19 | 11,075 | 22,664 |
| r=10% | 5,177 | 8,085 | 11,202 | 11,387 | 11,386 | 25,889 |

(c) Minimum of NPVs

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| r=4% | -18,462 | -40,636 | -41,743 | -56,544 | -37,938 | -291,623 |
| r=6% | -20,149 | -46,408 | -60,38 | -72,314 | -54,758 | -339,561 |
| r=8% | -21,546 | -47,153 | -79,748 | -89,842 | -72,66 | -429,258 |
| r=10% | -23,193 | -57,455 | -98,2 | -111,687 | -95,177 | -490,082 |

(d) Maximum of NPVs

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| r=4% | 31,539 | 40,424 | 40,804 | 32,698 | 49,824 | -120,582 |
| r=6% | 30,849 | 35,181 | 28,622 | 20,278 | 36,458 | -165,049 |
| r=8% | 27,293 | 30,059 | 17,069 | 8,299 | 22,245 | -210,803 |
| r=10% | 24,563 | 23,399 | 2,319 | -9,993 | 6,026 | -264,015 |

Table 2.5: NPV distributions statistics with different interest rates

(a) r=4%

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| **NGCC** | 1 | 0,1796 | 0,7559 | 0,7548 | 0,7572 | 0,4896 |
| **PC** | 0,1796 | 1 | 0,6583 | 0,6569 | 0,662 | 0,3654 |
| **Wind on** | 0,7559 | 0,6583 | 1 | 0,9843 | 0,9872 | 0,6364 |
| **Wind off** | 0,7548 | 0,6569 | 0,9843 | 1 | 0,985 | 0,6357 |
| **Hydro** | 0,7572 | 0,662 | 0,9872 | 0,985 | 1 | 0,637 |
| **PV** | 0,4896 | 0,3654 | 0,6364 | 0,6357 | 0,637 | 1 |

(b) r=6%

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| **NGCC** | 1 | 0,1911 | 0,7576 | 0,7559 | 0,759 | 0,4389 |
| **PC** | 0,1911 | 1 | 0,66 | 0,6592 | 0,6632 | 0,3295 |
| **Wind on** | 0,7576 | 0,66 | 1 | 0,976 | 0,9803 | 0,5677 |
| **Wind off** | 0,7559 | 0,6592 | 0,976 | 1 | 0,9781 | 0,5668 |
| **Hydro** | 0,759 | 0,6632 | 0,9803 | 0,9781 | 1 | 0,5685 |
| **PV** | 0,4389 | 0,3295 | 0,5677 | 0,5668 | 0,5685 | 1 |

(c) r=8%

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| **NGCC** | 1 | 0,2025 | 0,7576 | 0,7542 | 0,7602 | 0,3935 |
| **PC** | 0,2025 | 1 | 0,658 | 0,6575 | 0,6601 | 0,2955 |
| **Wind on** | 0,7576 | 0,658 | 1 | 0,9646 | 0,9698 | 0,5013 |
| **Wind off** | 0,7542 | 0,6575 | 0,9646 | 1 | 0,9671 | 0,5021 |
| **Hydro** | 0,7602 | 0,6601 | 0,9698 | 0,9671 | 1 | 0,5032 |
| **PV** | 0,3935 | 0,2955 | 0,5013 | 0,5021 | 0,5032 | 1 |

(d) r=10%

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| **NGCC** | 1 | 0,2087 | 0,7525 | 0,7485 | 0,7543 | 0,3387 |
| **PC** | 0,2087 | 1 | 0,6538 | 0,6515 | 0,6559 | 0,2624 |
| **Wind on** | 0,7525 | 0,6538 | 1 | 0,9482 | 0,954 | 0,4314 |
| **Wind off** | 0,7485 | 0,6515 | 0,9482 | 1 | 0,9504 | 0,431 |
| **Hydro** | 0,7543 | 0,6559 | 0,954 | 0,9504 | 1 | 0,4333 |
| **PV** | 0,3387 | 0,2624 | 0,4314 | 0,431 | 0,4333 | 1 |

Table 2.6: Correlations between NPVs for different interest rates

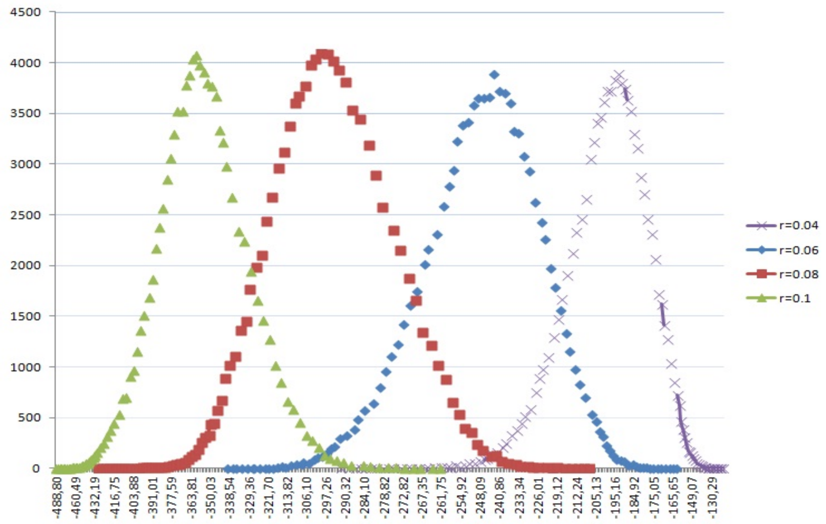


Figure 2.4: NPV distributions for PV for different interest rates

## 2.3 Optimal generation mean-variance portfolio

In this section we use return (mean of NPV), risk (standard deviation of NPV) and correlation obtained from the Monte Carlo simulations, to compute the optimal generating portfolio, based on the mean-variance approach. We have to solve the following problem:

$$\begin{cases} & \min \sigma(\mathrm{NPV}_p) \\ \text{s.t.} & E(\mathrm{NPV}_p) = \sum_{i=1}^{n} E(\mathrm{NPV}_i) x_i \\ & \sum_{i=1}^{n} x_i = 1 \\ & x_i \geq 0 \quad i = 1, \cdots, n \end{cases}$$

where $E(\mathrm{NPV}_p)$ and $\sigma(\mathrm{NPV}_p)$ represent respectively the mean and standard deviation of NPV of the portfolio, and $x_i$ represents the weight of technology $i$ expressed in term of installed capacity of technology $i$ over total installed capacity. The standard deviation of the portfolio is computed as:

$$\sigma(\mathrm{NPV}_p) = \sqrt{\sum_{i=1}^{n} x_i^2\sigma_i^2 + 2\sum_{i=1}^{n-1}\sum_{j=i+1}^{n} x_i x_j \sigma_i \sigma_j \rho_{ij}}$$

where $\rho_{ij}$ is the correlation coefficients between the NPVs of technologies $i$ and $j$.

We first consider the case of an electricity producer without any constraint on the production sources. We consider portfolio made of all possible technologies, when there aren't incentives on the production of renewable energy. We then consider the case of an electricity producer with a constraint on the choice of generation sources. He is indeed forced to produce a certain quota of his total energy production, from renewable sources.

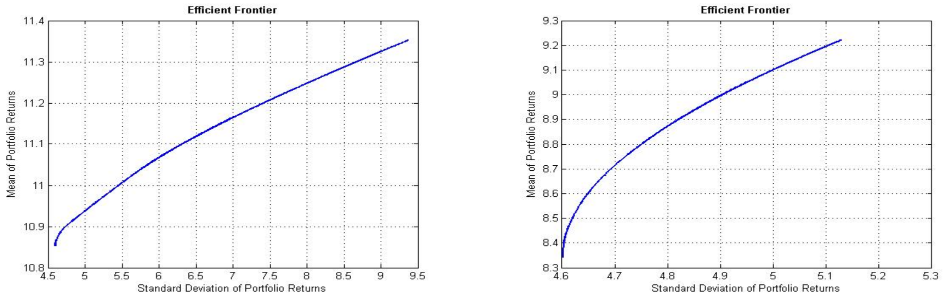
### 2.3.1 Optimal portfolio without constraints

Figure 2.5 shows the efficient MV frontiers obtained[4] considering all six technologies, in the case when there isn't any constraint on the electricity production. First thing we notice is that, as the interest rate increases, the efficient frontier obviously lowers, because the NPVs decrease. We can also see that the efficient frontier covers a smaller range of risk. Indeed the risk of the portfolios on the frontier goes from about 4,5 to about 9,5 when the interest rate is equal to 4%, while it goes from about 4,5 to about 4,8 when the interest rates are equal to 6%, 8% and 10%. So basically, as the interest

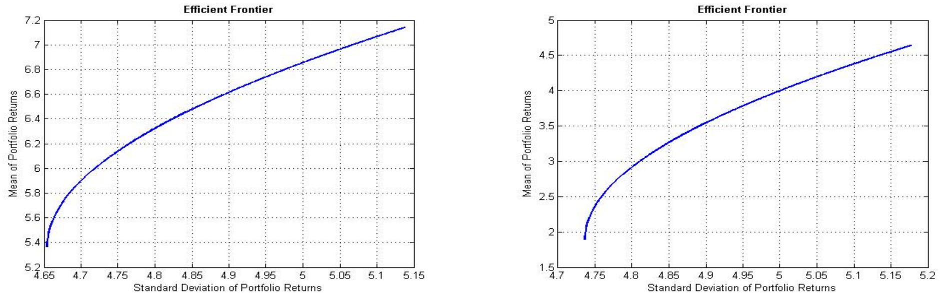
---

[4] We considered 1000 different portfolios

rates increases, the efficient frontier reduces. In this way the choices of the portfolio composition for the electricity producer become gradually smaller.



(a) r=4% (b) r=6%



(c) r=8% (d) r=10%

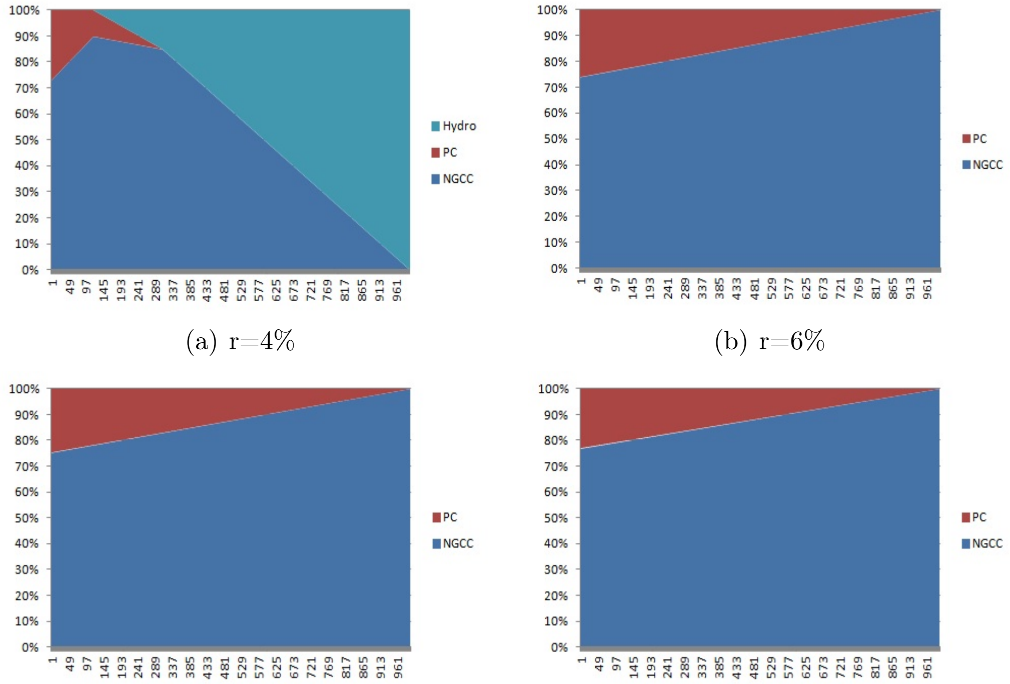
Figure 2.5: Efficient MV frontiers without constraints

If we look at the compositions of the portfolios[5] lying on the efficient frontiers (Figure 2.6), we see first of all that they are dominated by conventional technologies. Except when the interest rate is equal to 4%, the portfolios on the efficient frontier are composed only by conventional technologies. In the first case (Figure 2.6(a)), we have some portfolios that contain renewable technologies (hydro), whose quota increases as portfolio's risk increases. The last three cases (Figure6 2.6(b), 2.6(c) and 2.6(d)) are similar. We have portfolios dominated by NGCC, with a small quota of PC, that decreases as portfolio's risk increases. This confirms the results obtained by Roques et

---

[5] Portfolios are ordered from less to more risky

al.[60]. It confirms also the current trend of electricity production in Italy, where natural gas is the most used electricity generation source and its quota is increasing.



(a) r=4%

(b) r=6%

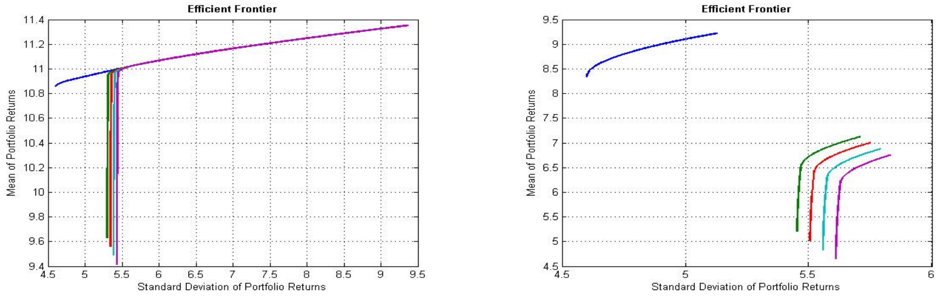
(c) r=8%

(d) r=10%

Figure 2.6: Portfolio compositions for different interest rates.

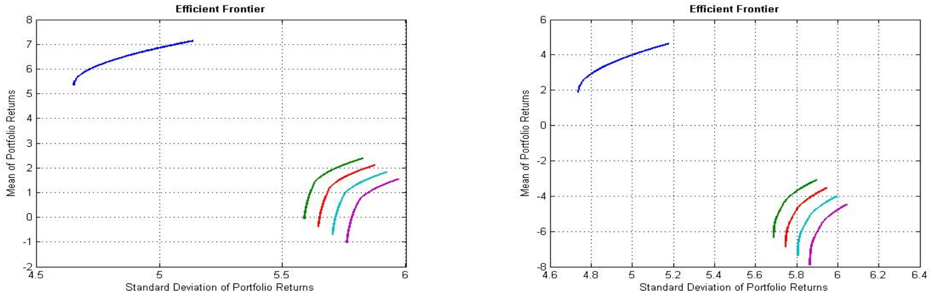
### 2.3.2 Optimal portfolio with constraints on renewables

In this section we see the efficient frontier obtained by placing a constraint on electricity production. We impose that the electricity producer must produce a certain quota of electricity from renewable sources. We suppose in particular a minimum of 17% of total electricity to be produced from renewable sources. This represents the target set for Italy by the EU for the energy production from renewable sources. We see what happens as this quota increases.



(a) r=4%

(b) r=6%

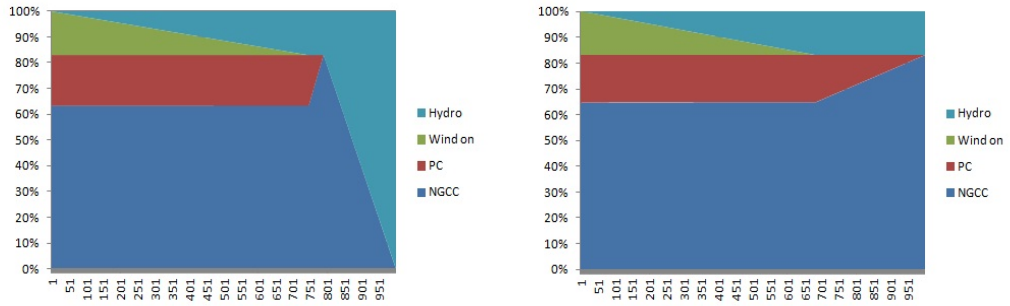


(c) r=8%

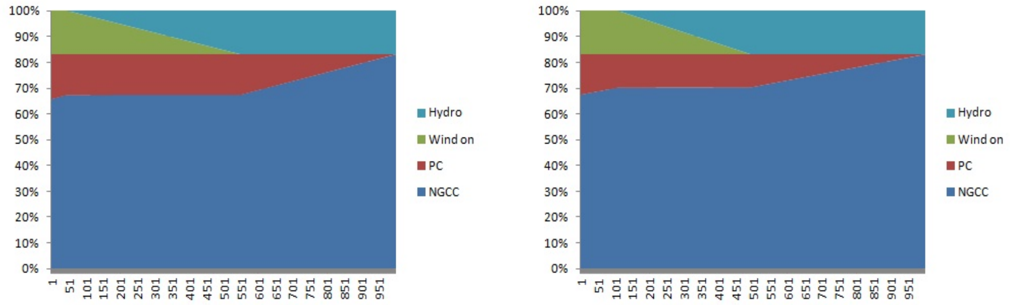
(d) r=10%

Figure 2.7: Efficient MV frontiers with constraints on renewable production

Figure 2.7 shows a comparison between the efficient frontier in the case of constraints and in the case without constraints. As we can see, the constraints reduce the feasible portfolios for the investor. In general there is an increase of risk with the same return, so the solutions obtained in the case of constraints are, as we could expect, sub-optimal. Moreover, as the constrained quota of renewables increases, the efficient frontier reduces and so the possibilities for the electricity producer decrease. This is clear especially in the case when the interest rates are equal to 4%. In this situation the efficient frontiers computed with constraints on renewables, partly overlap the efficient frontier without constraints, and as the renewable quota increases, the efficient frontier gradually reduces. Moreover, as the constrained renewable quota increases, portfolios' return decreases and becomes even negative. This is particularly evident in the case of $r = 10\%$ (Figure 2.7(d)) where returns of the portfolios lying on the constrained frontiers are always negative.



(a) r=4% (b) r=6%



(c) r=8% (d) r=10%

Figure 2.8: Portfolio compositions with constraints on renewables (17%)

If we look at the compositions of the portfolios lying on the efficient frontier, when the renewable quota is equal to 17% (Figure 2.8), the situation is slightly different than the previous case, when there aren't any constraints. We have portfolio dominated by conventional technologies, with renewable technologies that enter in the efficient frontier only for a quota equal to the constraint (except when $r = 4\%$). However, in this case we have two renewable technologies in the optimal portfolios: hydro and offshore wind.

In particular, offshore wind enters the composition of less risky portfolio and is gradually substituted by hydro as portfolio's risk increases.

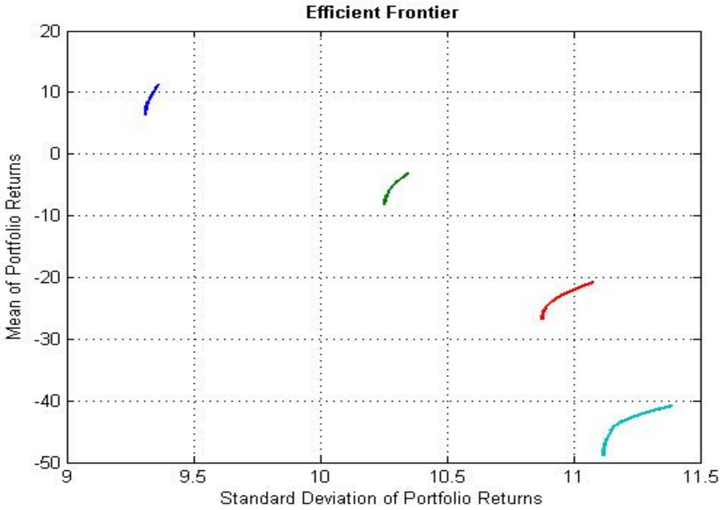
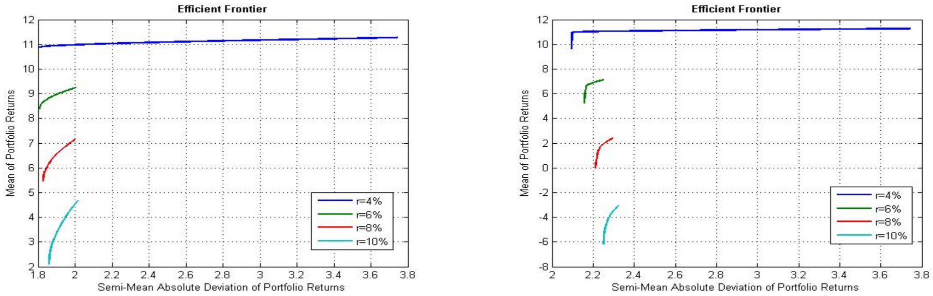


Figure 2.9: Efficient frontiers with 100% renewable technologies

If we consider the limit case of a portfolio composed only by renewable technologies, we would have an efficient frontier with portfolios composed only by offshore wind and hydro. Efficient frontiers in this situation are reported in figure 2.9. As we can see, portfolios lying on the frontiers exhibits always negative returns except in the case of $r = 4\%$. This is the only case where it would be economically efficient (from a risk-return perspective) to hold a portfolio made only of renewable sources (i.e. hydro).

## 2.4 Optimal SMAD portfolio

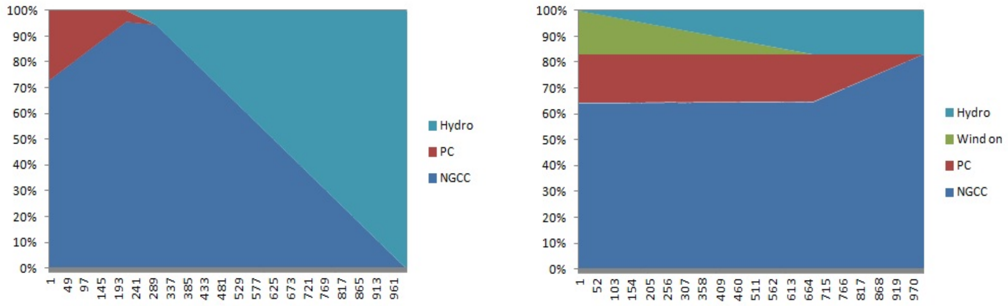
In this section we consider the optimal portfolio obtained when we use the SMAD model. The only difference between this model and the MV model is in the way we measure risk. In this case we consider only negative deviations from portfolio's mean, so we suppose that for an investor, only downside risk is relevant.



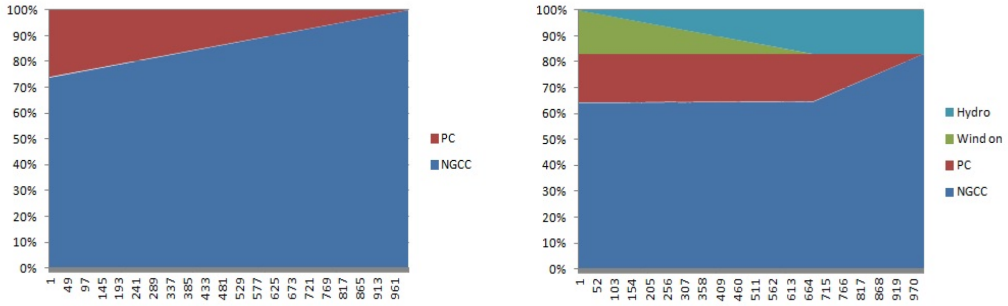
(a) Efficient frontier without constraints (b) Renewable quota at 17%

Figure 2.10: SMAD efficient frontiers

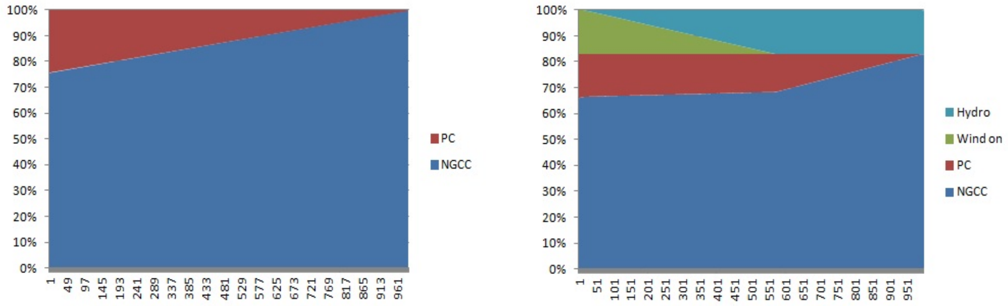
In figure 2.10 we report the results obtained by using the SMAD model. As we can see, the results in terms of expected return are similar to the one obtained with the MV model. If we look at portfolio composition ( Figure 2.11) we see that also in this case, the portfolios lying on the efficient frontier are dominated by conventional technologies. The results are similar to the case of MV model. This is due to the fact that NPV distributions are very close to normal. We con notice a little difference if we look at the case of constraints on renewable energy production, when $r = 10\%$. In this case we see that also wind offshore enters in the portfolio composition, although in a very small part.



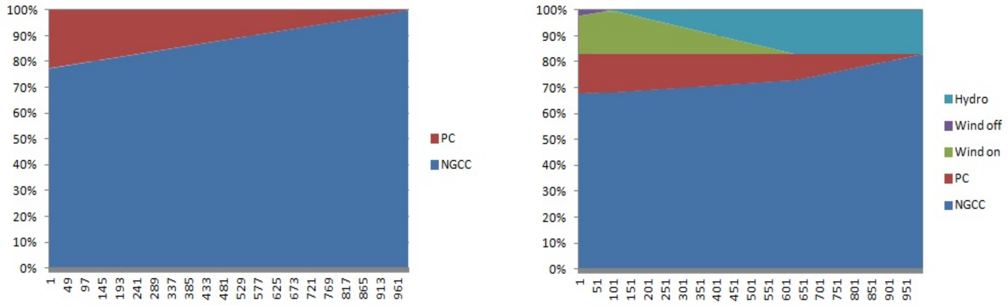
(a) No constraints (r=4%) (b) Renewable quota 17% (r=4%)



(c) No constraints (r=6%) (d) Renewable quota 17% (r=6%)



(e) No constraints (r=8%) (f) Renewable quota 17% (r=8%)



(g) No constraints (r=10%) (h) Renewable quota 17% (r=10%)

Figure 2.11: Portfolio compositions using SMAD model

# Chapter 3

# Incentives for renewable energy

## 3.1 Introduction

In this section we analyze the incentive schemes that are being currently adopted, with a particular focus on Italy and European Union. We then apply the model seen before to construct the optimal portfolio in the presence of incentives for renewable energy.

Before analyzing the support schemes we have to answer one question: why should renewable technologies be incentivated? First of all we have to say that, in order to ensure their development, the government involvement is essential in the initial phase, so as to protect them from direct competition with existing (conventional) technologies. Of course, without this support, market forces alone would end up in a limited diffusion of these technologies, and so there wouldn't be the possibility to benefit from learning effects in order to become competitive. However this doesn't answer the initial question.

The justification for a support by the government can be given by considering renewable energy sources as a way to correct negative externalities resulting from the use of fossil fuels and to achieve dynamic efficiency by stimulating technical change.

About the first point, the main characteristic of renewables is that they contribute to the preservation of public goods, such as clean air and climate stability. Public goods are non-excludable and non-rival. For these reasons, private sector is not encouraged to invest in something that everyone can acquire free of charge. With the liberalization of the electricity market there is a partial response to this problem. In this way we enable consumers who want to pay for these goods to purchase electricity produced from RES to a higher price. There could be however a problem of free-riding.

About the second point, we can say that a new technology will become efficient gradually as a result of the process of learning by using. So incentive system are required in order to allow the diffusion of renewable technology beyond their narrow market niche. This would result in a competition between traditional and new generating technologies, which would stimulate technical progress. This constitutes a sufficient justification for providing public support for renewable energies.

Finally there is the need of a support policy, coming from the European Directive 28/2009, which set for each country of the EU different targets about the quota of energy to be produced from renewable sources. For Italy in particular, the target has been set at 17%.

## 3.2 Different incentive types

If we consider the different incentive policies used in the European countries in the last years for the promotion of RES, we can divide them into four main categories: feed-in tariffs, capital subsidies, competitive bidding processes and tradable green certificates. These four categories are either price-based or quantity-based.

In a price-based approach, the public authority set a fixed price at which the electricity produced from renewable sources can be sold. In a quantity based approach, the authority set a quantity of energy that must be produced through renewable sources. We now see in detail the different incentive schemes.

### 3.2.1 Feed in tariffs

The feed-in tariff scheme falls in the price-based approaches. The main characteristic of a feed-in tariff policy is that it offers guaranteed prices for fixed periods of time for electricity from renewable energy sources. This involves an obligation by electricity utilities to purchase all the electricity produced by renewable energy producers, which operates in their service area.

There are different type of feed-in tariff schemes. The main distinction between different feed-in tariff policies lies on whether the remuneration they offer is dependent or independent from the actual electricity market price. Couture and Gagnon [24] identify seven different ways to structure a FIT, four falling in the market-independent category and three falling in the market-dependent category.

### Market independent FIT

All market-independent FIT policies are characterized by a fixed price at which the energy generated from RES will be bought for a contracted period of time. This price will remain fixed for all the duration of the contract, independently of the retail price of electricity.

We can have a *fixed price model* in which the price remains independent of all other variables, such as inflation or the price of fossil fuels. The fixed price is set by considering the cost of the renewable technology, so it is different for each type of renewable source considered.

Another option for market-independent FIT is a *fixed price model with full or partial inflation adjustment.* This protects the investor from a decline in real value of the project revenues, which is a possible disadvantage of the *fixed price model.*

A third market-independent FIT policy option is the *front-end loaded model.* With this policy, higher payments are offered during the first years of project's life, while lower payments are offered in the last years.

A last variant of market-independent FIT is the *spot market gap model.* In this model, the payment consists of the difference between the spot electricity market price and a fixed price. So the total remuneration in this model is a fixed price consisting in the electricity market price plus a variable compensation in order to reach the fixed payment. In this model, as electricity prices increases, the variable premium decreases and vice versa. If the electricity price is higher than the fixed price, then the premium is negative.

### Market dependent FIT

Market-dependent FIT policies are characterized by variable payments, which depend on the actual market electricity price.

The first market-dependent FIT policy option we examine is the *premium price model.* In this model a fixed constant payment is offered above the market electricity price. In this way, total payment fluctuates according to the market price of electricity and renewable energy producers receive more when electricity price goes up and less when electricity price goes down.

A second possible market-dependent policy option is represented by the *variable premium price model.* In this policy option, the premium amount declines gradually as retail price increases, until the retail price reaches a certain level, after which the premium is equal to zero. When this happens the renewable electricity producer receives the spot market price. Figure 3.1 shows a representation of how this policy works. A policy design of this type was recently introduced in Spain.

The last FIT policy option we consider, is the *percentage of the retail price model.* In this model the payment made to the renewable energy producer consists of a fixed percentage of the retail electricity price. This makes the remuneration received by renewable energy producers totally dependent on changes in the market electricity price. This model was used in Germany and in Denmark in the 1990s and in Spain between 2004 and 2006.

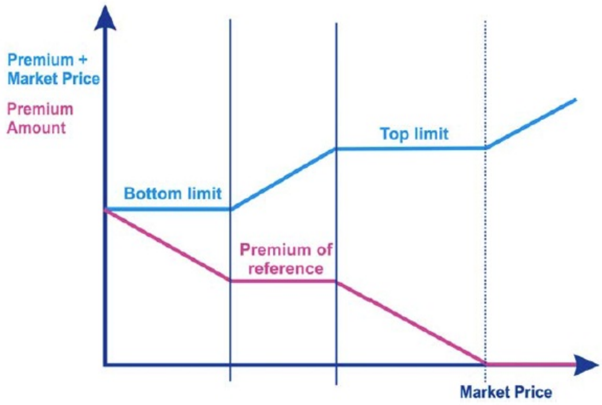


Figure 3.1: Variable premium FIT policy design. Source: Couture and Gagnon (2010)

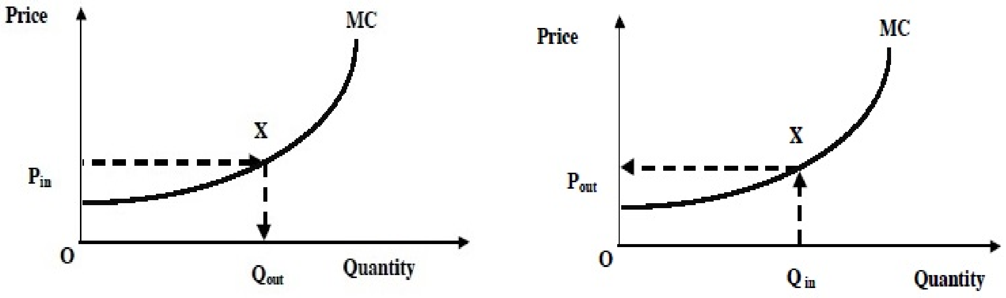
### 3.2.2 Capital subsidies

Capital subsidies are, like feed in tariffs, a price-based policy instrument. This is the easiest incentive scheme to implement. With this incentive policy, the renewable energy producer simply receives from the government a quota of the capital cost in which he incurred for the construction of a new renewable energy plant. This gives the opportunity to the electricity producer to cover part of the initial expenses, but then his remuneration is equal to the one received by a conventional energy producer.

### 3.2.3 Competitive bidding processes

Competitive bidding processes fall in the quantity-based incentive category. With these type of incentive policy, the authority defines a reserved market for a given amount of renewable energy and organizes a competition between renewable energy producers in order to allocate this amount. As in the case of feed in tariffs, electric utilities are obliged to purchase electricity from these producers. In this case however, the price is not fixed.

All renewable electricity producers compete with each other on the price per kWh. In the bidding process all the proposals are classified in increasing order of cost until the amount of energy set by the regulator is reached. Each producer then will supply electricity with a long term contract, at the bid price. In this case the marginal cost is represented by the cost of the last selected project.



(a) Feed-in tariff (b) Competitive Bidding Process

Figure 3.2: Feed-in tariff vs competitive bidding process. Source: Menanteau et al. (2003)

Figure 3.2 summarizes the difference between feed-in tariffs and competitive bidding processes. In the first case (3.2(a)) we start from the price ($P_{in}$) to determine the quantity produced ($Q_{out}$) and the total cost of reaching the target is given by the area $P_{in} \times Q_{out}$. In the case of competitive bidding (3.2(b)) processes, we start from the quantity to be produced ($Q_{in}$) to determine the marginal price ($P_{out}$). In this case the overall cost of reaching the target is given by the area under the marginal cost curve.

### 3.2.4 Green certificates

Like competitive bidding processes, also green certificates are a quantity-based policy instrument. In a system based on green certificates, renewable electricity producers sell their energy in the usual electricity market at market prices. So there isn't any obligation by electric utilities to purchase electricity from renewable producers. At the same time the producers receive a certain quantity of certificates for every MWh of electricity produced and they can sell this certificates in a separate market. So the remuneration for renewable producer is made of two components: the price of electricity and the price of the certificates.

The certificates are demanded by obligated buyers (conventional electricity suppliers or consumers) who must buy a quantity of certificates corresponding to a certain quota of their total energy production or consumption. This obligated buyers can choose whether to buy the green certificates or to purchase the green energy directly from a renewable energy producer or even decide to produce renewable energy by themselves.

Green certificates are a market instrument in the sense that their value is not fixed, but depends on the demand and supply. In this case electricity producers don't know with certainty their remunerations. The overall amount of green electricity to be generated is decided for the whole country and then is divided among each operator. Since operators have different marginal production cost curves, green certificates enable quotas to be distributed in an efficient way.

Incentive schemes based on green certificates are also known with the name of Renewable Portfolio Standard (RPS) (see for example [57]).

## 3.3 The current situation of incentives

### 3.3.1 Incentives in Italy

After the approval of the Climate-Energy package by the European Council on 12 December 2008 and the following European Directive (28/2009), which set as a target for Italy that by 2020, energy produced from renewable sources should be equal to 17% of total energy production, the Italian government set a series of incentive schemes to reinforce the support to renewable energies.

The incentive schemes adopted by Italy (but also by other countries) has focused mainly on the electricity sector, neglecting almost entirely the heating sector, although the European directive doesn't put any distinction between these two types of energy.

The support schemes adopted for renewable energy adopted in Italy, belong to both price-based and quantity-based categories. In particular, they are classified in: Conto Energia, Certificati Verdi, Tariffa Omincomprensiva and CIP6 system.

Conto Energia is a price-based incentive. It is in particular a fixed price FIT, which guarantees to the electricity producer a fixed payment for a period of twenty years. This type of incentive has been given in particular for the PV sector. There has been five different incentive programs starting from 2005. The last program (Quinto Conto Energia) started in 2010 end ended in July 2013, without the emanation of a new program.

Certificati Verdi (Green Certificates) are a quantity based incentive, as explained above. They were introduced by the Legislative Decree 79/99 and are awarded to renewable plants for electricity production from wind and water, which came into operation before 31 December 2012.

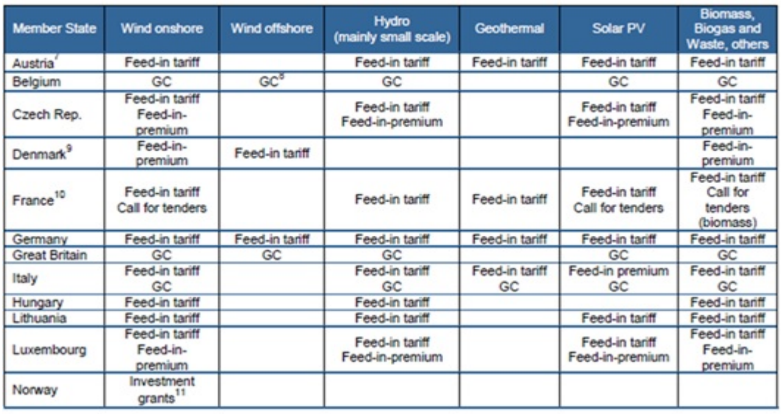
Tariffa Omnicomprensiva is a fixed price FIT, which represents an alternative to the Green Certificates for the electricity produced from hydro and wind. The electricity producer is rewarded with this fixed tariff for a period of fifteen years.

CIP6 system started on 29 April 1992 with a decision of Comitato Interministeriale Prezzi (CIP). It is a price-based incentive and in particular belongs to the premium price FIT category. in fact it consists in a fixed price paid for the electricity produced from renewable sources in addition to the market price of electricity. The CIP6 tariff has been suspended for the new plants.

### 3.3.2 Incentives in Europe

Figure 3.3 shows a summary of support schemes currently adopted in Europe. As we can see, most of the countries considered adopt feed-in tariffs as support for renewable energies. Only few countries (including Italy) use green certificates. This has brought to a huge increase of the policy costs for supporting renewables, which has been reflected on an increase of the electricity bill paid by final customers.

This increase in costs has been acknowledged both theoretically and practically, as we can see for example in Falbo et al. (2008), where an analysis performed on wind incentives (in Italy and in Germany) showed that feed-in tariffs were excessively high, and a support scheme based on market type incentive could have achieved better results in term of costs for the whole country.



| Member State | Wind onshore | Wind offshore | Hydro (mainly small scale) | Geothermal | Solar PV | Biomass, Biogas and Waste, others |
|---|---|---|---|---|---|---|
| Austria[7] | Feed-in tariff | | Feed-in tariff | Feed-in tariff | Feed-in tariff | Feed-in tariff |
| Belgium | GC | GC[8] | GC | | GC | GC |
| Czech Rep. | Feed-in tariff<br>Feed-in-premium | | Feed-in tariff<br>Feed-in-premium | | Feed-in tariff<br>Feed-in-premium | Feed-in tariff<br>Feed-in-premium |
| Denmark[9] | Feed-in-premium | Feed-in tariff | | | | Feed-in-premium |
| France[10] | Feed-in tariff<br>Call for tenders | | Feed-in tariff | Feed-in tariff | Feed-in tariff<br>Call for tenders | Feed-in tariff<br>Call for tenders (biomass) |
| Germany | Feed-in tariff | Feed-in tariff | Feed-in tariff | Feed-in tariff | Feed-in tariff | Feed-in tariff |
| Great Britain | GC | GC | GC | | GC | GC |
| Italy | Feed-in tariff<br>GC | | Feed-in tariff<br>GC | Feed-in tariff<br>GC | Feed-in premium<br>GC | Feed-in tariff<br>GC |
| Hungary | Feed-in tariff | | Feed-in tariff | | | Feed-in tariff |
| Lithuania | Feed-in tariff | | Feed-in tariff | | Feed-in tariff | Feed-in tariff |
| Luxembourg | Feed-in tariff<br>Feed-in-premium | | Feed-in tariff<br>Feed-in-premium | | Feed-in tariff<br>Feed-in-premium | Feed-in tariff<br>Feed-in-premium |
| Norway | Investment grants[11] | | | | | |

Figure 3.3: RES Support schemes for electricity production. Source: CEER 2011

Currently most countries are progressively reducing support to renewable energy, as in the case of Italy. However, there is still a huge burden for the countries due to the incentives, which still have to be paid for the existing plants.

## 3.4 Assessment of the different policies

There is currently a strong debate about which policy is the most efficient for the development of renewable technologies. In particular the debate is focused mainly in the comparison between two different support schemes: feed-in tariffs and green certificates. We see here a brief review of the literature about the assessment of these different incentive policy, highlighting the advantages and disadvantages of each support scheme.

Menanteau et al. [49] examine the efficiency of the different support schemes, both from a theoretical and a practical point of view, by looking at examples of how these instruments have been implemented. They conclude that feed-in tariffs are more efficient than a bidding system, but they highlight the theoretical advantages of a green certificate system.

Falbo et al. [31] use data from the Italian green certificate market, to show that an incentive system based on certificates rather than feed-in tariffs is more consistent with the target of the equality between expected profit from electricity production from a renewable and a conventional plant (the so called "grid parity").

Bergek and Jacobsson [12] use data from Swedish tradable green certificate (TGC) market to show that a TGC system should be selected if the main concern is to minimize short term social costs of reaching the EU target. This is confirmed also by Aune et al. [4] who show that a TGC market may help to cut the EU's total cost of fulfilling the target by as much as 70%. However the development of a TGC market cannot be expected to drive technical change, keep consumer costs down and be equitable.

Jenner et al. [39] focus their attention on the FIT system. They analyze in particular the FIT policies implemented in EU in the 1992-2008 time period. Their analysis confirm the shared opinion that feed in tariffs helped the development of the RES capacity in Europe, especially for solar PV. However, this could have been done in a way that has been too expensive.

Other studies about the assessment of the different support schemes can be found in [66], [54], [58], [61], [45], [52], [51], [50], [41], [29], [24], [16] and [7].

# Chapter 4

# Optimal electricity portfolio with incentives for renewables

In this section we apply the same model, we have seen in the previous chapter, to compute the optimal portfolio of electricity production, when renewable technologies receive incentives from the government. We consider different incentive schemes for each technology. In particular we suppose that electricity production from wind and hydro plants is rewarded with green certificates [1], while photovoltaic plants are supported with a feed-in tariff [2], which is the actual support policy applied in Italy in the last years. In this way we could also evaluate the effectiveness of this policy.

---

[1] We suppose that the electricity producer receives for a period of time of 15 years 1 green certificate for every MWh of electricity produced from an hydro or an onshore wind plant, while it receives 1,5 certificates for every MWh of electricity produced from an offshore wind plant.

[2] We suppose that the electricity producer receives a fixed tariff for 20 years equal to 343 €/MWh, which is the average tariff paid from 2008 to 2012 under the Conto Energia incentive scheme.

Green certificates represent a further risk factor for the renewable electricity producer. Price of green certificates is not fixed and varies according to the market. We supposed that green certificates prices are normally distributed and we included them in the Monte Carlo simulations in order to compute the new NPVs of the plants under the assumption of incentives for renewables. We used prices of green certificates from 2008 to 2012 to compute the mean, the standard deviation and the correlations between GC and the other variables previously considered. Data are taken from Bloomberg database.

Table 4.1 reports a summary of the data. As we can see, correlations between green certificates and the other variables are always negative.

(a)

| | **Unit** | **Mean** | **St. Deviation** |
|---|---|---|---|
| **Green certificates** | €/MWh | 83,14 | 4,44 |

(b)

| | **Electricity (average)** | **Electricity (peak)** | **Natural gas** | **Coal** | **EUA** |
|---|---|---|---|---|---|
| **Correlations** | -0,776 | -0,638 | -0,516 | -0,406 | -0,234 |

Table 4.1: Mean, standard deviation and correlations of GCs

## 4.1 Net Present Values

We report here the distributions of the NPVs of each plant under the assumption of incentives for renewables. Figure 4.1 shows the distributions obtained with the Monte Carlo simulations.

As we can see, with incentives, renewable technologies become competitive with conventional ones. Even PV, which in the previous case had an NPV far below the NPVs of the other technologies, is competitive at least when interest rate used for evaluation is low.

If we look at the statistics of the NPV distributions (table 4.2 and 4.3), we see that the introduction of incentives, not only increases the mean of renewable NPVs, but also decreases their standard deviation, thus decreasing risk. This partly confirms the results obtained by Falbo et al. [31]. In particular the risk related to a PV plant heavily reduces especially in the case of low interest rates. However, renewable plants are still more risky than NGCC plants. Conventional plants NPVs instead slightly decreases, because with a green certificates market, the conventional producer is forced to buy a quantity of certificates equal to a certain quota of total electricity production[3].

Looking at the correlations, the major change compared to the previous case concerns the PV. In fact, we have that the NPVs of a PV plant are almost uncorrelated with all other plants. This is due to the fact that with a feed-in tariff, the revenues for a PV plant are almost fixed for the whole plant life. The only factor, which affects revenues is the capacity factor of

---

[3] We supposed here a quota of 2%

the plant, which we assumed to be independent from the other risk factors.

(a) Mean of NPVs

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| r=4% | 9,663 | 9,143 | 44,855 | 56,283 | 46,605 | 35,650 |
| r=6% | 7,950 | 4,487 | 37,542 | 50,672 | 39,852 | -2,166 |
| r=8% | 5,851 | -1,302 | 28,419 | 43,022 | 30,901 | -49,273 |
| r=10% | 3,344 | -8,374 | 17,395 | 33,438 | 19,848 | -105,438 |

(b) Standard deviation of NPVs

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| r=4% | 5,116 | 7,658 | 6,444 | 6,103 | 7,032 | 9,794 |
| r=6% | 5,099 | 7,729 | 6,352 | 6,039 | 6,841 | 13,494 |
| r=8% | 5,114 | 7,952 | 6,352 | 5,978 | 6,787 | 18,016 |
| r=10% | 5,188 | 8,275 | 6,471 | 5,915 | 6,741 | 22,648 |

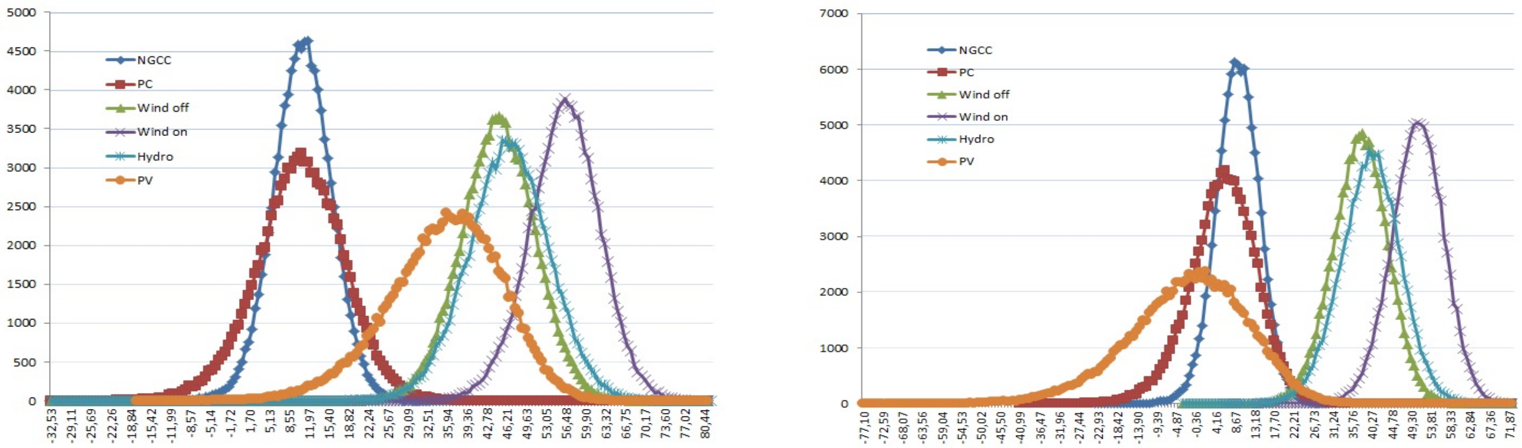
(c) Minimum of NPVs

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| r=4% | -9,443 | -19,059 | 16,276 | 27,703 | 15,080 | -21,351 |
| r=6% | -11,525 | -24,467 | 8,473 | 23,406 | 8,620 | -95,424 |
| r=8% | -14,624 | -31,018 | 0,287 | 16,068 | 1,107 | -153,193 |
| r=10% | -17,588 | -38,740 | -15,789 | 8,736 | -11,306 | -232,715 |

(d) Maximum of NPVs

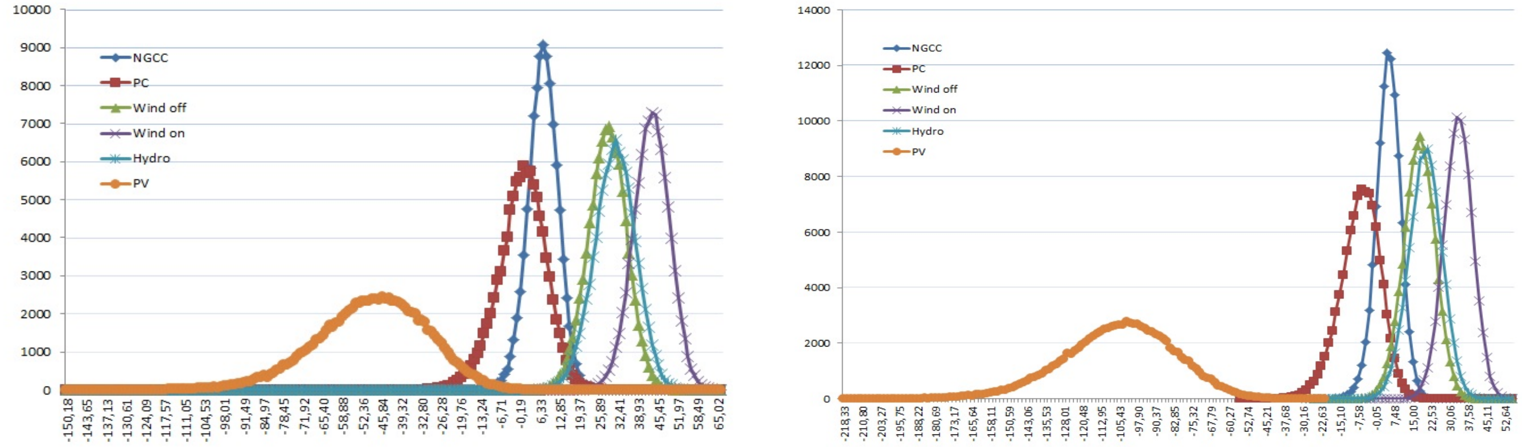
| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| r=4% | 31,981 | 40,921 | 73,950 | 82,833 | 75,775 | 72,821 |
| r=6% | 28,290 | 36,981 | 63,845 | 77,514 | 68,802 | 41,278 |
| r=8% | 28,491 | 28,505 | 54,357 | 66,839 | 58,886 | 11,299 |
| r=10% | 23,759 | 22,603 | 43,215 | 57,175 | 46,566 | -24,665 |

Table 4.2: NPV distributions statistics with incentives for renewables



(a) r=0,04

(b) r=0,06



(c) r=0,08

(d) r=0,1

Figure 4.1: NPVs distributions with incentives for renewables

(a) r=4%

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| **NGCC** | 1,000 | 0,187 | 0,746 | 0,708 | 0,754 | 0,002 |
| **PC** | 0,187 | 1,000 | 0,622 | 0,582 | 0,635 | 0,001 |
| **Wind on** | 0,746 | 0,622 | 1,000 | 0,957 | 0,975 | 0,004 |
| **Wind off** | 0,708 | 0,582 | 0,957 | 1,000 | 0,951 | 0,004 |
| **Hydro** | 0,754 | 0,635 | 0,975 | 0,951 | 1,000 | 0,003 |
| **PV** | 0,002 | 0,001 | 0,004 | 0,004 | 0,003 | 1,000 |

(b) r=6%

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| **NGCC** | 1,000 | 0,196 | 0,740 | 0,695 | 0,749 | 0,000 |
| **PC** | 0,196 | 1,000 | 0,614 | 0,568 | 0,627 | 0,003 |
| **Wind on** | 0,740 | 0,614 | 1,000 | 0,941 | 0,966 | 0,002 |
| **Wind off** | 0,695 | 0,568 | 0,941 | 1,000 | 0,938 | 0,001 |
| **Hydro** | 0,749 | 0,627 | 0,966 | 0,938 | 1,000 | 0,002 |
| **PV** | 0,000 | 0,003 | 0,002 | 0,001 | 0,002 | 1,000 |

(c) r=8%

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| **NGCC** | 1,000 | 0,201 | 0,730 | 0,674 | 0,740 | 0,000 |
| **PC** | 0,201 | 1,000 | 0,607 | 0,551 | 0,616 | -0,003 |
| **Wind on** | 0,730 | 0,607 | 1,000 | 0,918 | 0,950 | -0,003 |
| **Wind off** | 0,674 | 0,551 | 0,918 | 1,000 | 0,917 | -0,004 |
| **Hydro** | 0,740 | 0,616 | 0,950 | 0,917 | 1,000 | -0,004 |
| **PV** | 0,000 | -0,003 | -0,003 | -0,004 | -0,004 | 1,000 |

(d) r=10%

| | **NGCC** | **PC** | **Wind on** | **Wind off** | **Hydro** | **PV** |
|---|---|---|---|---|---|---|
| **NGCC** | 1,000 | 0,207 | 0,717 | 0,651 | 0,726 | -0,001 |
| **PC** | 0,207 | 1,000 | 0,589 | 0,527 | 0,603 | 0,000 |
| **Wind on** | 0,717 | 0,589 | 1,000 | 0,884 | 0,922 | -0,003 |
| **Wind off** | 0,651 | 0,527 | 0,884 | 1,000 | 0,885 | -0,003 |
| **Hydro** | 0,726 | 0,603 | 0,922 | 0,885 | 1,000 | -0,001 |
| **PV** | -0,001 | 0,000 | -0,003 | -0,003 | -0,001 | 1,000 |

Table 4.3: Correlations between NPVs with incentives for renewables

## 4.2 Efficient frontiers with incentives on renewables

Figure 4.2 shows the efficient frontiers obtained in the case of incentives for renewable technologies, while figure 4.3 shows a comparison between the two cases. As we can see, the efficient frontiers obtained with incentives dominate the efficient frontiers obtained in the previous case. So there is a huge increase of the possible production mixes available to the electricity producer.

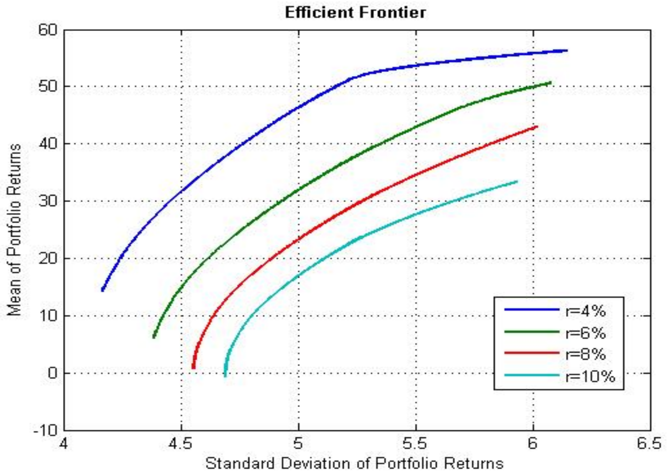


Figure 4.2: Efficient MV frontiers with incentive for renewables

If we look at the composition of the portfolios lying on the efficient frontier, the situation is much different from the previous case. We now have more renewable technologies in the portfolio. In particular in this case wind offshore and PV enter in the portfolio composition, with a quota that increases as portfolio's risk increases.

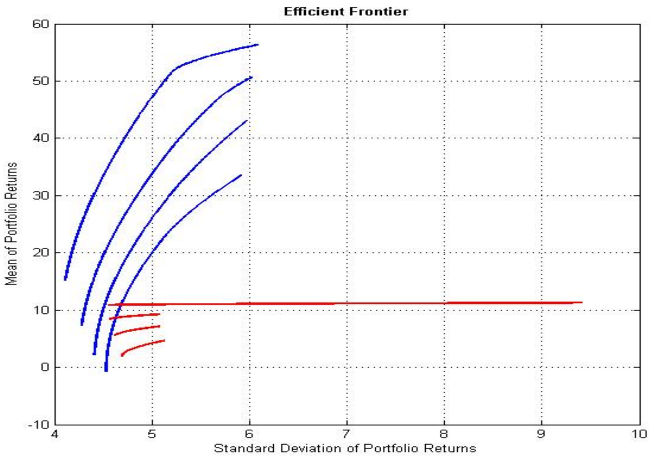
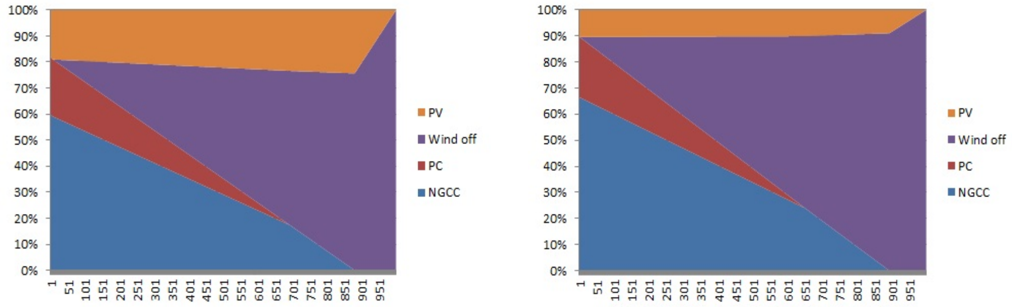
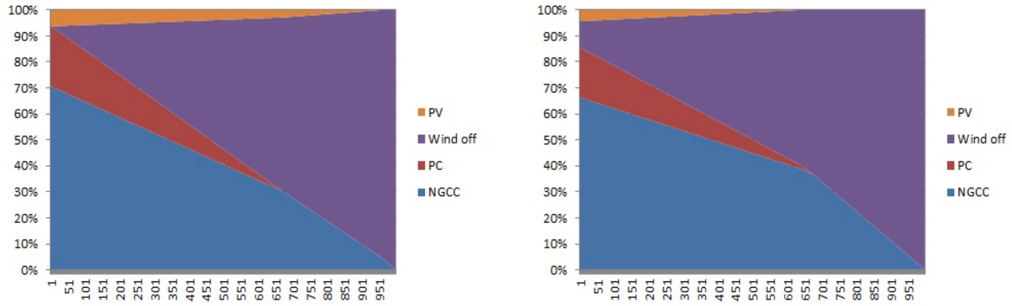


Figure 4.3: Efficient frontiers without incentives vs efficient frontiers with incentives



(a) r=4%

(b) r=6%



(c) r=8%

(d) r=10%

Figure 4.4: Portfolio compositions with incentives on renewables.

In the case of incentives for renewables it is also possible (and economically convenient from a risk-return perspective) for the electricity producer, to have an electricity production entirely made from renewable sources.

Figure 4.5 shows a comparison between efficient frontiers containing all technologies (blue lines) with efficient frontiers containing only renewables (green lines). Obviously in the second case there is a reduction of the possibilities for the electricity producer, but there is at least one portfolio which is feasible in both cases, so there is at least one portfolio containing only renewables, which is efficient. This didn't happen in the previous case where we supposed the absence of government support for renewables.

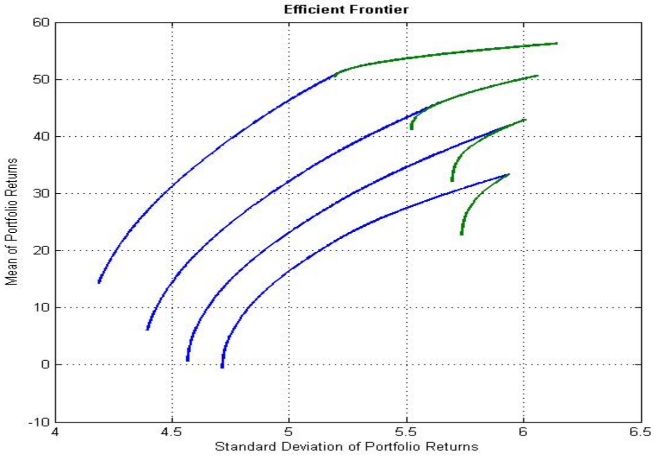


Figure 4.5: Efficient frontiers containing all technologies vs efficient frontiers containing only renewables

# Conclusions

The analysis performed shows some interesting results, which allow us to give an assessment of the actual incentive policy and to suggest some refinements for future policies.

The first important result is that, without incentives, no electricity producer would invest in renewable technologies. The only exception is represented by hydro, which however has limited development opportunities, given that the hydro sources in Italy have been almost completely exploited. If we analyze the italian policy of incentives, based on this result, we can say that the target of improving the efficiency of renewable technology, in order to reduce their costs has been missed. Renewable technologies are still too much expensive and cannot compete with conventional sources, unless some kind of support is given.

Another important results concerns the evaluation of the actual support policy set by the Italian government. If we look at the portfolios obtained considering incentives for renewables, we see that these incentives favored in particular two technologies: offshore wind and PV. In particular, for PV, we have a situation of a technology, with a NPV far below the NPV of the other technologies, that, with incentive, becomes competitive. With incentives, not only renewable technologies become competitive with conventional ones, but they become in some situations even more profitable. Therefore, the same results could have been obtained with a less expensive support scheme, or with a different distribution of incentives among the various technologies. Thus, a possible improvement to the actual incentive policy could be to use a support scheme more based on green certificates rather than fixed feed in tariffs. In this way, only more competitive technologies could be favored, with a less expensive policy.

Finally, it should be observed that all the results of this work are obtained for the Italian market, with plant costs and fuel and electricity prices corresponding to the period 2008-2012. Further research should be focused on confirming these results by taking also into account possible variations of plant costs, especially for renewable plants, which could decrease in the future.

# Bibliography

[1] AA VV. *Rapporto statistico 2011*. Report. GSE, 2012.

[2] AA VV. *Rapporto sulle energie rinnovabili (edited by S. Stefani and A. Caridi)*. Report. Energylab, 2011.

[3] Nicholas Apergis and James E. Payne. “Renewable energy consumption and economic growth: Evidence from a panel of OECD countries”. In: *Energy Policy* 38 (2010).

[4] Finn R. Aune, Hanne M. Dalen, and Cathrine Hagem. “Implementing the EU renewable target through green certificate markets”. In: *Energy Economics* 34 (2012).

[5] Shimon Awerbuch. *Portfolio-Based Electricity Generation Planning: Implications for Renewables and Energy Security*. Report. REEEP, 2004.

[6] Shimon Awerbuch and Martin Berger. *Applying Portfolio Theory to EU Electricity Planning and Policy-making*. Report. IEA/EET, 2003.

[7] Nasser Ayoub and Naka Yuji. “Governmental intervention approaches to promote renewable energies—Special emphasis on Japanese feed-in tariff”. In: *Energy Policy* 43 (2012).

[8] Dan Bar-Lev and Steven Katz. “A Portfolio Approach to Fossil Fuel Procurement in the Electric Utility Industry”. In: *Journal of Finance* 31 (1976).

[9] Galen Barbose, Ryan Wiser, and Mark Bolinger. “Designing PV incentive programs to promote performance: A review of current practice in the US”. In: *Renewable and Sustainable Energy Reviews* 12 (2008).

[10] Kemal Baris and Serhat Kucukali. “Availability of renewable energy sources in Turkey: Current situation, potential, government policies and the EU perspective”. In: *Energy Policy* 42 (2012).

[11] Matthew J. Bellamy. “Explorers”. In: *The 2nd Law* (2012).

[12] Anna Bergek and Staffan Jacobsson. “Are tradable green certificates a cost-efficient policy driving technical change or a rent-generating machine? Lessons from Sweden 2003–2008”. In: *Energy Policy* 38 (2010).

[13] Anindya Bhattacharya and Satoshi Kojima. “Power sector investment risk and renewable energy: A Japanese case study using portfolio risk optimization method”. In: *Energy Policy* 40 (2012).

[14] Christoph Boehringer, F. Thomas Rotherford, and Richard S.J. Tol. “The EU 20/20/2020 targets: An overview of the EMF22 assessment”. In: *Energy Economics* 31 (2009).

[15] Christoph Boehringer et al. “EU climate policy up to 2020: An economic impact assessment”. In: *Energy Economics* 31 (2009).

[16] Stefan Boeters and Joris Koorneef. “Supply of renewable energy sources and the cost of EU climate policy”. In: *Energy Economics* 33 (2011).

[17] Anatole Boute. “Promoting renewable energy through capacity markets: An analysis of the Russian support scheme”. In: *Energy Policy* 46 (2012).

[18] Michael C. Brower et al. *Evaluating the risk-reduction benfits of wind energy.* Report. U.S. Department of Energy, 1997.

[19] Veit Buerger et al. “Policies to support renewable energies in the heat market”. In: *Energy Policy* 36 (2008).

[20] Lucy Butler and Karsten Neuhoff. “Comparison of feed-in tariff, quota and auction mechanisms to support wind power development”. In: *Renewable Energy* 33 (2008).

[21] Sanya Carley. “State renewable energy electricity policies: An empirical evaluation of effectiveness”. In: *Energy Policy* 37 (2009).

[22] Corinne Chaton and Marie-Laure Guillerminet. “Competition and environmental policies in an electricity sector”. In: *Energy Economics* 36 (2013).

[23] Peter Connor et al. “Devising renewable heat policy: Overview of support options”. In: *Energy Policy* (in press).

[24] Toby Couture and Yves Gagnon. “An analysis of feed-in tariff remuneration models: Implications for renewable energy investment”. In: *Energy Policy* 38 (2010).

[25] Pat DeLaquil, Shimon Awerbuch, and Kristin Stroup. *A Portfolio-Risk Analysis of Electricity Supply Options in the Commonwealth of Virginia.* Report. December 2005.

[26] Erik Delarue et al. “Applying portfolio theory to the electricity sector: Energy versus power”. In: *Energy Economics* 33 (2011).

[27] Ecofys. *Financing Renewable Energy in the European Energy Market.* Report. European Commission, DG Energy, January 2011.

[28] Ottmar Edenhofer. *The IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation.* Report. IPCC, September 2011.

[29] Riccardo Fagiani, Julian Barquin, and Rudi Hakvoort. “Risk-based assessment of the cost-efficiency and the effectivity of renewable energy support schemes: Certificate markets versus feed-in tariffs”. In: *Energy Policy* 55 (2013).

[30] Paolo Falbo, Daniele Felletti, and Silvana Stefani. “Free EUAs and fuel switching”. In: *Energy Economics* 35 (2013).

[31] Paolo Falbo, Daniele Felletti, and Silvana Stefani. “Incentives for Investing in Renewables”. In: *H. German (Ed.) Risk* 40 (2008).

[32] Zvonimir Glasnovic and Jure Margeta. “Vision of total renewable electricity scenario”. In: *Renewable and Sustainable Energy Reviews* 15 (2011).

[33] Douglas Gotham et al. “A load factor based mean–variance analysis for fuel diversification”. In: *Energy Economics* 31 (2009).

[34] Robert Gross, William Blyth, and Philip Heptonstall. “Risks, revenues and investment in electricity generation: Why policy needs to look beyond costs”. In: *Energy Economics* 32 (2010).

[35] Mirijam Harmelink, Monique Voogt, and Clemens Cremer. “Analysing the effectiveness of renewable energy supporting policies in the European Union”. In: *Energy Policy* 34 (2006).

[36] T.E. Hoff. *Integrating Renewable Energy Technologies in the Electric Supply Industry: A Risk Management Approach.* Report. NREL, July 1997.

[37] Claus Huber et al. “Economic modelling of price support mechanisms for renewable energy: Case study on Ireland”. In: *Energy Policy* 35 (2007).

[38] J.C. Jansen, L.W.M Beurskens, and X. van Tilburg. *Application of portfolio analysis to the Dutch generating mix.* Report. ECN, 2006.

[39] Steffen Jenner, Felix Groba, and Joe Indvik. “Assessing the strength and effectiveness of renewable electricity feed-in tariffs in European Union countries”. In: *Energy Policy* 52 (2013).

[40] Malcolm Keay. “Renewable energy targets: the importance of system and resource costs”. In: *Oxford Energy Comment* (2013).

[41] Corinna Klessmann et al. “Policy options for reducing the costs of reaching the European renewables target”. In: *Renewable Energy* 57 (2013).

[42] Hiroshi Konno and Hiroaki Yamazaki. “Mean-absolute deviation portfolio optimization model and its applications to Tokyo stock market”. In: *Management Science* 37 (1991).

[43] Ulrike Lehr, Christian Lutz, and Dietmar Edler. “Green jobs? Economic impacts of renewable energy in Germany”. In: *Energy Policy* 47 (2012).

[44] Ulrike Lehr et al. “Renewable energy and employment in Germany”. In: *Energy Policy* 36 (2008).

[45] Jonathan A. Lesser and Xuejuan Su. “Design of an economically efficient feed-in tariff structure for renewable energy development”. In: *Energy Policy* 36 (2008).

[46] Yixuan Liu and Zhongfeng Qin. “Mean Semi-absolute Deviation Model for Uncertain Portfolio Optimization Problem”. In: *Journal of Uncertain System* 6 (2012).

[47] Natalia Magnani and Andrea Vaona. “Regional spillover effects of renewable energy generation in Italy”. In: *Energy Policy* 56 (2013).

[48] Harry Markowitz. “Portfolio Selection”. In: *The Journal of Finance* 7 (1952).

[49] Philippe Menanteau, Dominique Finon, and Marie-Laure Lamy. “Prices versus quantities: choosing policies for promoting the development of renewable energy”. In: *Energy Policy* 31 (2003).

[50] Toufic Mezher, Gihan Dawelbait, and Zeina Abbas. “Renewable energy policy options for Abu Dhabi: Drivers and barriers”. In: *Energy Policy* 42 (2012).

[51] Catherine Mitchell, D. Bauknecht, and Peter M. Connor. “Effectiveness through risk reduction: a comparison of the renewable obligation in

England and Wales and the feed-in system in Germany”. In: *Energy Policy* 34 (2006).

[52] Catherine Mitchell and Peter Connor. “Renewable energy policy in the UK 1990–2003”. In: *Energy Policy* 32 (2004).

[53] Jose Ignacio Munoz et al. “Optimal investment portfolio in renewable energy: The Spanish case”. In: *Energy Policy* 37 (2009).

[54] Richard G. Newell, Adam B. Jaffe, and Stavins Robert N. “The effects of economic and policy incentives on carbon mitigation technologies”. In: *Energy Economics* 28 (2006).

[55] M.P. Pablo-Romero, A. Sanchez-Braza, and M. Perez. “Incentives to promote solar thermal energy in Spain”. In: *Renewable and Sustainable Energy Reviews* 22 (2013).

[56] Karen Palmer and Dallas Burtraw. “Cost-effectiveness of renewable electricity policies”. In: *Energy Economics* 27 (2005).

[57] Karen Palmer et al. “Federal policies for renewable electricity: Impacts and interactions”. In: *Energy Policy* 39 (2011).

[58] Sara Proenca and Miguel St. Aubyn. “Hybrid modelling to support energy-climate policy: Effects of feed-in tariffs to promote renewable energy in Portugal”. In: *Energy Economics* (to appear).

[59] Fabien Roques, Celine Hiroux, and Marcelo Saguan. “Optimal wind power deployment in Europe—A portfolio approach”. In: *Energy Policy* 38 (2010).

[60] Fabien A. Roques, David M. Newbery, and Nuttall William J. "Fuel mix diversification incentives in liberalized electricity markets: A Mean–Variance Portfolio theory approach". In: *Energy Economics* 30 (2008).

[61] Gisele Schmid. "The development of renewable energy power in India: Which policies have been effective?" In: *Energy Policy* 46 (2012).

[62] Malte Sunderkoetter and Christoph Weber. *Valuing fuel diversification in optimal investment policies for electricity generation portfolios.* Working Paper. Chair for Management Sciences and Energy Economics, November 2009.

[63] A. Tolon-Becerra, X. Lastra-Bravo, and F. Bienvenido-Barcena. "Proposal for territorial distribution of the EU 2020 political renewable energy". In: *Renewable Energy* 36 (2011).

[64] Aviel Verbruggen and Volkmar Lauber. "Basic concepts for designing renewable electricity support aiming at a full-scale transition by 2050". In: *Energy Policy* 37 (2009).

[65] Peerapat Vithayasrichareon and Iain F. MacGill. "A Monte Carlo based decision-support tool for assessing generation portfolios in future carbon constrained electricity industries". In: *Energy Policy* 41 (2012).

[66] Yan Wang. "Renewable electricity in Sweden: an analysis of policy and regulations". In: *Energy Policy* 34 (2006).

[67] J. West, I. Bailey, and M. Winter. "Renewable energy policy and public perceptions of renewable energy: A cultural theory approach". In: *Energy Policy* 38 (2010).

[68] Rolf Wuestenhagen and Emanuela Menichetti. “Strategic choices for renewable energy investment: Conceptual framework and opportunities for further research”. In: *Energy Policy* 40 (2012).

[69] Lei Zhu and Ying Fan. “Optimization of China’s generating portfolio and policy implications based on portfolio theory”. In: *Energy* 35 (2010).

# List of Figures

# List of Tables