3

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A CASE STUDY ON RISK AND RETURN IMPLICATIONS OF EMISSIONS TRADING IN POWER GENERATION INVESTMENTS

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Abstract:

This paper explores quantitative implications of the European Union Emissions Trading Scheme (EU ETS) on power capacity investment appraisal in a deregulated market. Risk and return of three different types of power plants, a gas-fired condensing power plant; a hydro power plant with a reservoir; and an off-shore wind power farm, are studied and compared in the regulatory environment of Finland. A single-firm exogenous and stochastic price model is used to simulate possible market outcomes. The model runs suggest that emissions trading increases the expected return of all three power plant technologies. The increase in risk is significant only in the case of the gas-fired power plant.

Keywords:

Investment, power generation, emissions trading

INTRODUCTION

An opportunity cost for greenhouse gas (GHG) emissions has become a new factor influencing investments in power generation capacity globally, and in particular in countries with an emissions trading system. The European Union Emissions Trading Scheme (EU ETS) launched in January 2005 is the most prominent example of a greenhouse gas emissions trading system. The EU ETS introduces a considerable and fundamental price risk to the investment problem ("what is the value of emission allowances of different vintage?") (see e.g. Springer and Varilek; 2004). The character of the price risk is somewhat different from that of fuels or electricity, which can be considered "genuine necessities" and are already traded in large volumes ("will emissions trading continue after 2012?"). IEA (2003, p. 31) characterizes the price risk as a "potentially critical uncertainty in power generation investment". This price risk is present in all green-field investments and power plant retrofits within the European Community. It is also present in acquisitions and divestments of power production licences or capacity.

Exposure of different types of power plant technologies to the risks of emissions trading differs (Table 1). For example, *a combined-cycle gas turbine (CCGT)* is a technology characterized by *control* and *operating flexibility* regarding production (e.g. IEA, 2003, Moreira et al., 2004). The plant can fairly well be adjusted to the changing market conditions on a weekly and monthly level. It is run only, if its *spark spread*, i.e. the revenue from electricity production minus the variable cost, is positive. Thus, it can capture a large proportion of the best hours to produce electricity, while avoiding the unprofitable hours. It has a valuable *option to alter operating scale* (e.g. Hsu, 1998, Laurikka and Koljonen, 2005, Fleten and Näsäkkälä, 2004, Näsäkkälä and Fleten, 2004, Tseng and Barz, 2002). However, there is a *fuel price* risk (e.g. Bolinger et al. 2004, Weber and Swider 2004). The EU ETS brings along direct additional risks through the impact of surrendered allowances, market price of power, and the free emission allowances (Laurikka and Koljonen, 2005). A value for carbon dioxide emissions can have either a positive or a negative impact on the value of a CCGT.

A *wind power farm* is a technology characterized by a low flexibility regarding optimization of production due to its intermittent nature (e.g. IEA, 2003). In many countries, e.g. Germany, the output price risk (for the investor) is eliminated through the fixed feed-in tariffs provided by the government. In others, e.g. Finland, the value profile of the electricity produced depends on the correlation of the local winds with power prices. On the other hand, the allowance price risk is present only through the market price of electricity and potentially subsidies.

Table 1. Total risk factors of the power generation technologies examined.

Total risk factor	Combined cycle gas turbine (CCGT)	Wind power plant	Hydro power plant with a reservoir
Technical (availability) risk	X	X	X
Public acceptance	X	X	X
Power price risk	X	X	X
Fuel price risk	X	-	-
Allowance price risk[1]	X	-	-
Allowance allocation risk	X	-	-
Subsidy risk / Windfall profit tax risk	-	X	X
Production volume risk	-	stochastic on a daily level	stochastic on an annual level

[1]direct impact

The adjustability of *hydro power plants with reservoirs* on a daily level is good. The technology is characterized by a *stochastically limited* flexibility regarding optimization of production, since the annual precipitation is stochastic, and the ability to transfer production from a year to the next is often limited due to the size of the reservoir. It must also be noted that correlations of wind and precipitation conditions can differ.

This paper explores quantitative implications of the EU ETS on power capacity investment appraisal in a deregulated market. Applying a single-firm exogenous and stochastic price simulation model[1], I examine risk and return of the three power plant types above in the regulatory environment of Finland. Whereas, the CCGT and the off-shore wind power farm are realistic green-field plant options, valuation of hydro power has more relevance in acquisitions due to the highly exploited technological potential. The objective is to quantify the change in risk and return and to compare the technologies.

Section 2 briefly reviews literature on risk management in power generation investments. Section 3 presents the model used in the case study. Data applied in modeling are presented in Section 4, and the results of modeling are discussed in Section 5. Finally, the implications of the results are discussed in Section 6.

RISK MANAGEMENT IN POWER GENERATION INVESTMENTS

The Modigliani-Miller paradigm[2] of finance implies that investors able to hold a well-diversified portfolio of assets would generally not benefit from corporate-level actions to mitigate risk. In standard financial theory, the expected return on any asset is assumed to depend on its risk level. The total risk of **Table 1** on the other hand comprises *systematic* and *unsystematic* components. Systematic risk, also called "the *market* risk" influences a large number of assets, and is determined through the underlying factors of the economy, such as interest rates, recessions and wars. In contrast, unsystematic risk (also: *asset-specific* or *unique* risk) affects at most a small number of assets. An investor with a large portfolio of assets can thus diversify away the unsystematic risk. For this reason, the expected return of an asset should only depend on the systematic part of the total risk.

However, companies *do* manage total risk, e.g. through the use of derivatives (see below). Several hypotheses ranging from cost of financial distress, investment policies and taxes to managerial utility maximization, have been made by financial economists, why corporate-level risk management could be rational or value-enhancing (e.g. Froot et al. 1993, Tufano 1996, Fatemi and Luft 2002). It has also been argued that closely held companies would engage in risk management more likely than companies with diffuse ownership (Mayers and Smith, 1982).

[1] For a taxonomy on energy system models, see Ventosa et al. (2005).

[2] The paradigm says that in an idealized world without e.g. transactions costs, taxes and information costs, managers could not benefit their shareholders through active risk management.

In power generation industry many companies are still closely held and one can ask, if the investors - in many cases e.g. municipalities – really do have well-diversified portfolios. In these circumstances, corporate-level risk mitigation may matter, since the investors cannot (or *do* not) diversify away all of the conventional asset-specific risk. For power generation, such non-diversifiable asset-specific risk could include the price of electricity or (some part of) the price of an emission allowance. A portfolio of different fuels and/or technologies would reduce the risks related to individual plants or "*plant-specific"* risks, such as technical availability or local wind speed. It would also reduce the risk related to the variable costs (e.g. fuel price, value of emission allowances to be surrendered). However, it would not get rid of all of the asset-specific risk, which would eventually be present in the market price of electricity. The electricity market then again partly reflects the market value of emission allowances. This remaining risk could also be called a "*business-specific"* risk, since it can only be diversified away through investments outside the business.

Financial hedging instruments, such as forwards, futures, swaps and options, can be used to decrease the total risk (e.g. Keppo, 2002, Tanlapco et al., 2002, Vehviläinen and Keppo, 2002). However, the use in the investment problem is – at least in the current situation - restricted by liquidity. This insufficiency has two dimensions. First, the time horizon of investments is very long, whereas financing instruments are principally available for periods up to three years ahead (IEA, 2003). Second, emissions trading can make inclusion of new and even more illiquid financing instruments, such as weather derivatives, more important (Biello, 2004). As the EU ETS introduces totally new risks to the investment project (allowance price, number of free allowances[3]), hedging also becomes more challenging than before.

Another way to secure future income is an appropriate diversification of tangible assets (Hoff and Herig, 1996, IEA, 2003, p. 49). Awerbuch (e.g. 2000a, 2000b, 2004) argues that *portfolio-based* analyses, which optimize cost and risk, should be preferred to *stand-alone* project analyses. This implies that the value of the project would depend on the existing generating asset portfolio of the investor. The question arises, however, if this is too restrictive: e.g. Gustafsson (2004) explores valuation of projects in an environment, where the investor can invest both in financial securities and in a portfolio of private projects.

MODEL

The model used in this paper makes a Monte Carlo simulation of selected stochastic variables in order to compare the dynamic performance of the three technologies *simultaneously* in different scenarios for emissions trading. It is based on the assumption that all the investment alternatives share the same *systematic* risk. This is a common practice in power plant valuations (see e.g. IEA/NEA 2005, IEA, 2003). I thereby explore the total risk of the technologies excluding technical and

[3] See e.g. Laurikka and Koljonen (2005) for review.

construction-related risks (e.g. IEA, 2003). The hypothesis is that business-specific risks discussed above differ between technologies.

The total risk is explored through the volatility of *long-term* returns of power plant investments. This implies that I consider a simplified case, where an investor makes an irreversible investment at time t_0, and obtains the return on the investment gradually during the investment lifetime [t_0, t_1]. For simplicity, I exclude the case that the asset can be traded and/or closed down during [t_0, t_1]. This implies that the investor is *not* interested in short- to mid-term fluctuations in the asset value. The expected return on the initial investment, *I*, becomes:

$$E(ROI) = \frac{E(\sum DCF) - I}{I} = \sum \frac{E(CF_i)}{IR^i} - 1 \tag{1}$$

where *R* is the risk-adjusted discount factor.

A standard discounted cash flow (DCF) analysis is extended to better reflect the value of the option to alter operating scale (O_{scale}) for the CCGT. The extended net present value of an investment NPV_{ext} thus becomes[4]:

$$NPV_{ext} = NPV + O_{scale} \tag{2}$$

with *NPV* being the simple Net Present Value of the investment based on the expected cashflows. If O_{scale} is much larger than zero, the simple NPV analysis fails to valuate the investment correctly.

The value of *real options* is ideally estimated in a risk-neutral valuation framework (see e.g. Dixit and Pindyck, 1994, 120-121). I approach the value of the options through a *dynamic discounted cash flow analysis*[5] in a normal risk-adjusted valuation framework, which is applicable in incomplete markets. The starting point is a manager, who applies a *subjective* experience-based discount rate or the Weighted Average Cost of Capital (WACC) for the valuation problem.

Further, the following assumptions have been made in the model:

(1) The investment decision needs to be made in 2005;

(2) There are five stochastic variables with a constant correlation matrix ρ:

- the price of electricity without emissions trading ($p_{e,base}$)
- the price of an emission allowance (p_{CO2});
- the price of natural gas (p_g);
- the full-load hours of hydro power (x_h); and
- the full-load hours of wind power (x_w);

(3) The stochastic variables follow discrete-time continuous-state processes;

(4) $p_{e,base}$, p_{CO2}, and p_g are lognormally distributed so that the expected value is given by the user and the volatility (σ_i) is given as:

[4] For more on "extended NPV", see Trigeorgis (1995).

[5] See Teisberg (1995)

$$\sigma_t^2 = \frac{\sigma^2}{2\kappa}(1 - e^{-2\kappa t}) \tag{3}$$

where κ is the rate of mean reversion, and σ the volatility at present. The time series thus resemble those of an Ornstein-Uhlenbeck process (Dixit and Pindyck, 1994, 74-75). The time period in the model is a year.

(5) x_w and x_h are normally distributed. There is a small positive probability that this causes negative values, but with the data applied this has negligible practical implications. The volatility of x_w and x_h is simply σ.

(6) Deterministic variables include the number of free allowances (N); and the tax subsidy for wind power in Finland (φ). Different scenarios with varying probabilities can be applied to the deterministic variables. The number of free allowances is considered independent on the operating strategy of the gas plant (there is no updating procedure);

(7) p_{CO2} and p_g are constant within a year.

(8) There are no switching costs (start-up or shut-down costs)[6];

(9) The price of electricity directly depends on the allowance price (See e.g. ECON 2004; Electrowatt-Ekono 2003, Koljonen et al. 2004). As in Laurikka and Koljonen (2005), the market price of electricity, p_e, is separated to two parts, the "baseline" (business-as-usual) part ($p_{e,base}$) and the "CO_2-driven" part ($\gamma \cdot p_{CO2}$):

$$p_e = p_{e,base} + \gamma \cdot p_{CO2} \tag{4}$$

where γ is the estimated transformation factor. This is equal to the emission factor of the marginal plant, which results from the merit order in the power system. The transformation factor γ thus depends on the fluctuation in electricity supply and demand. Equation 4 allows the explicit modelling of γ. A further advantage is that there is historical data on $p_{e,base}$, whereas a little is known about p_e. The electricity supply in the Nordic countries - and thereby the price of electricity - significantly varies with hydrological conditions. However, the *form* of the price duration curve varies much less. Therefore, I add two more simplifying assumptions:

(10) The marginal plant (type) in the power system and thus the transformation factor γ is a function of $p_{e,base}$ and the expected value for the emission allowance price, $E(p_{CO2})$, so that[7]:

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[6] See Tseng and Barz (2002) for the importance of switching costs.

[7] This equation is derived from Laurikka (2005), who applies a simple non-linear regression to the results of ECON (2004). ECON (2004) show that the increase in the Nordic market price of electricity is a function of precipitation and of the expected value for emission allowances. If the latter is high, investments in new capacity will reduce the marginal emission factor, γ. The maximum value for γ (0.77) represents a coal-fired condensing power plant on the margin. γ must always be non-negative.

$$\begin{cases} \gamma(E(p_{CO2}), p_{e,base}) = Max\left[0,\ Min\left\{0.77,\ Ap_{e,base}{}^2 + Bp_{e,base} + C\right\}\right]\ so\ that: \\ A = -0.00012302 \cdot E(p_{CO2}) + 0.00223075 \\ B = 0.00205598 \cdot E(p_{CO2}) - 0.04110245 \\ C = 0.44116282 \end{cases} \tag{5}$$

(11) The *form* of the duration curve of $p_{e,base}$ within any single year is constant, i.e. the proportions of peak and bottom prices vs. the average level are constant.

From Equation 4 we thus obtain for the spark spread of the gas plant:

$$S_g = p_{e,base} - \frac{p_g}{\eta} + (\gamma(p_{e,base}, E(p_{CO2})) - \frac{e_g}{\eta}) p_{CO2} - \psi \tag{6}$$

where η is the thermal efficiency, e_g the emission factor and ψ the operation and maintenance cost. The annual cashflow (CF_G) before income tax becomes:

$$CF_G = P_{\max} \int \max\left[S_g, 0\right] dt + Np_{CO2} - C_f - T \tag{7}$$

where C_f is the fixed cost; and T represents a potential additional tax for power generation. The annual cashflow of the hydro power plant (CF_H) is calculated as:

$$CF_H = P_{\max} \int_0^{x_h} \left[p_{e,base} + \gamma(p_{e,base}, E(p_{CO2})) p_{CO2}\ \right] dt - C_f - T \tag{8}$$

where the integral is taken over the best hours of the year. It is thus simplistically assumed that hydro power producers can perfectly predict when to produce. The annual cashflow of the wind power plant (CF_W) is:

$$CF_W = P_{\max} x_w \left[\alpha p_{e,base} + \alpha\gamma(p_{e,base}, E(p_{CO2})) p_{CO2} + \varphi\right] - C_f - T \tag{9}$$

where α is the estimated profile factor reflecting the timing[8] of wind power production in the power system, and φ is the tax subsidy for production. Thus, CF_W is not considered risk-free due to its exposure to electricity market price and emission allowance price risk.

The model applies an optimal input correlation matrix for the state variables. As the correlation matrix is given by the user and is potentially based on heterogenic data, it can contain inconsistent information, i.e. it is not necessarily positively semi-definite. The matrix is thus checked and corrected before simulation

[8] If the profile factor > 1 then the timing is beneficial in terms of spot power prices, and vice versa.

with the spectral decomposition procedure of Rebonato and Jäckel (1999). Before simulation the rows and columns of the matrix are also organized so that the computational error in the expected result correlation matrix is minimized[9].

DATA

Constant parameters

The results are based on a simultaneous simulation of all three technologies with 1,000 runs in each scenario. Constant parameters are based on literature and press releases (Table 2). The investment cost and production estimates of the *off-shore wind power farm* are very much site-dependent. If the plant is situated near the coast, it produces more electricity, but the investment and O&M-costs are in all probability higher (Smekens et al., 2003; VTT, 2001), which is not considered here in detail. For this reason, the values quoted here should be seen as indicative only. The profile factor (α) used in the simulation is 1.0. Monthly production and spot price data from 1996-2004 assuming perfect prediction for wind power give a profile factor of 1.02. Similar figures have been obtained from simulations for the Nordic countries (1.02) and hourly data (0.98-1.02) for Finland and Sweden in 2001-2002 assuming perfect prediction and geographically dispersed production (Holttinen, 2004).

Table 2. Technology parameters.

Constants	Symbol	Unit	Gas plant	Wind farm	Hydro power plant
Output capacity	P_{max}	MW_e	250	150	325[3]
Operating lifetime	T_p	a	25[2]	25[4,5]	15[3]
Thermal efficiency	η	%	55[4]	-	-
Investment cost	I	€/kW_e	570[2]	1,450[5,6]	810[3]
Fixed cost	C_f	€/MW_e	11,000[2]	44,000[4,5]	25,000[2,4]
O&M costs and fees[1]	ψ	€/MWh_e	1.7[2,4]	-	-
Tax for power production	T	%	0	0	27 % of taxable cashflow
CO_2 emission factor	e_f	gCO_2/kWh	201	0	0
Full load hours on the average	x	h	max. 7,500	2,400 (near shore)[5] 3,000 (off-shore)[6]	4,000[3]

[1]includes a precautionary stock fee, [2]Ryden, 2003, [3]Kymppivoima, 2004; EPV, 2004, [4]Smekens et al., 2003, [5]based on PVO Engineering, 2001, [6]VTT, 2001.

[9] See also Laurikka (2005).

Hydro power data are based on a recent trade between Etelä-Pohjanmaan Voima (EPV) and the Norwegian Statkraft within the Nordic Market, where the former leased 325 MW_e of hydropower production capacity for 15 years (Kymppivoima, 2004, EPV, 2004). The price was €263 million (EPV, 2004). The annual full-load hours are estimated at 4,000 h (Kymppivoima, 2004). There is an additional tax (T) for income from power production in Norway ("Grunnrenteskatt"), in which the taxable cashflow depends on the book accounts; the allowed tax-free rate of return; the spot market price and production. This tax is modeled here only roughly.

Stochastic variables and scenarios

Historical data and various estimates about future prices are used as parameters of the stochastic processes (**Table 3**). A high rate of mean reversion and a low volatility imply that the price is likely to be close to the expected value. There are two scenarios for the allowance price (**Table 4**). A constant correlation matrix (**Table 5**) based on historical data is applied. Similarly to the allowance price scenarios, two scenarios for the correlation of the allowance price with other stochastic variables are tested (**Table 6**).

Table 3. Assumptions on the stochastic variables.

Variable	Symbol	Unit	Stochastic process	Long-run average	Volatility (%)	Rate of mean reversion
Annual average price of electricity (without emissions trading)	$p_{e,base}$	€/MWh	Lognormally distributed	24.1	33[1]	0.5[1]
Allowance price				See **Table 4**		
Price of natural gas	p_g	€/MWh	Lognormally distributed	2010: 14.0[2] 2020: 16.1[2] 2030: 18.2[2]	13[1]	0.3[1]
Full-load hours of wind power	x_{wind}	h	Normally distributed	2,400 (near shore)[5] 3,000 (off-shore)[6]	10	-
Full-load hours of hydro power	x_{hydro}	h	Normally distributed	4,000	10	-

[1]Based on data from 1996-Sep/Oct 2004 (Nordpool, 2004; Electrowatt-Ekono, 2004)
[2]Based on data from IEA(2004) vs. 2003 prices
[3]Based on Nordpool data from 1990-10/2004 using the average price during the period (10.4 €/MWh)
[5]PVO Engineering, 2001
[6]VTT, 2001.

Feasibility of combined cycle gas turbines is largely dependent on the assumptions made on prices *and* initial allocation of emission allowances (e.g. Laurikka and Koljonen 2005). Therefore two scenarios for allocation of allowances are tested. In the first one, the free initial allocation is continued forever with tightening caps (from 6,000 reference hours before 2008 to 3,000 reference hours in 2020). In the "auction" scenario, the initial allocation is switched to auction after 2012. Both of these options can be considered realistic at this point from the point of view of an investor. It is the probabilities that matter. In the base case, I use a probability of 0.5 for both.

Table 4. Scenarios for the allowance price.

Scenario	Symbol	Unit	Stochastic process	Long-run average	Volatility (%)	Rate of mean reversion
"Low, well-predictable allowance price"	p_{CO2}	€/tCO_2	Lognormally distributed	10	20	0.2
"High, unpredictable allowance price"	p_{CO2}	€/tCO_2	Lognormally distributed	10 (-2007) 20 (2008-)	30	0.2

Table 5. User's input correlation matrix.

Stochastic variable	Annual average price of electricity (without emissions trading)	Price of natural gas	Full-load hours of wind power	Full-load hours of hydro power
Annual average price of electricity (without emissions trading)	1	0.5[2]	0.1[1]	-0.7[1]
Price of natural gas		1	0.1[1]	0[3]
Full-load hours of wind power			1	0.2[1]
Full-load hours of hydro power				1

[1]based on annual average (gas on a monthly basis, electricity on a weekly basis) data in Finland 1996-2003
[2]based on annual average (gas on a monthly basis, electricity on a weekly basis) data in Finland 1996-2004
[3]based on annual average data in Finland 1990-2003

Wind power currently obtains a tax subsidy in Finland of 6.9 €/MWh. The subsidies are under consideration at the moment, and the long-term position of the subsidy is uncertain. I consider a scenario where the subsidy is removed after 2012 due to the increased competitiveness and set the probability to 0.5 in the base case. I further assume that the subsidy is reduced anyway by 20 %. In addition to the tax subsidy, I assume an investment subsidy of 20% in the base case. The annual full-load hours are assumed to be 2,400 h in the "base scenario".

Table 6. Correlation scenarios for the allowance price.

Scenario	Annual average price of electricity (without emissions trading)	Price of natural gas	Full-load hours of wind power	Full-load hours of hydro power
"No correlations" scenario	0	0	0	0
"Correlations" scenario	0.3	0.7	0	-0.3

RESULTS

The model runs show that emissions trading increases the expected return of all three power plant technologies (**Table 7**) with the function γ assumed for the marginal emission factor. The increase in risk is significant only for the CCGT: emissions trading can almost triple the total risk of the CCGT. The absolute increase in the risk of the wind power plant is very small, and the hydro power plant seems profitable in spite of volatility within an emissions trading scheme.

Table 7. Expected return on investment (*E(ROI)*) and its standard deviation (in brackets) in the „base-scenarios" (based on 1,000 model runs).

Scenario	"No correlations"		"Correlations"	
No emissions trading	CCGT: -84% (5.4%) Wind: -72 % (4.3%) Hydro: -6% (2.7%)			
"Low, well-predictable allowance price"	CCGT: Wind: Hydro:	-36% (8.0 %) -57% (4.4 %) +19% (3.2 %)	CCGT: Wind: Hydro:	-47% (8.1%) -56% (4.4%) +21% (3.3%)
"High, unpredictable allowance price"	CCGT: Wind: Hydro:	-8% (11%) -45% (4.4 %) +37% (3.4 %)	CCGT: Wind: Hydro:	-2% (13 %) -42% (4.5%) +44% (4.2%)

In the base-scenarios, the investment in the CCGT seems non-viable, but emissions trading decreases the expected loss. The investment becomes viable in the "correlations" scenario with a high allowance price, if the free of charge allocation is certain (**Table 8**): *E(ROI)* = +6% (σ = 8.8%). On the other hand, certainty about an auction scheme increases the expected loss to –11% (σ = 9.3%).

The off-shore wind power farm seems viable only in the most optimistic case (**Table 8**). Certainty in tax subsidy for production, a higher number of full-load hours (3,000) and a higher investment subsidy of 30% in the best emissions trading scenario (high allowance price, correlations) gives modest positive numbers for the project. Emissions trading alone is not enough if the subsidies are removed.

The investment in the hydro power plant seems to become profitable in an emissions trading environment. The expected return can grow up to 44% with the allowance price scenarios tested without a significant impact on risk.

From the risk management perspective, it is interesting to note that the correlations of the project returns are fairly low (0.15–0.61) in scenarios, where the regulatory uncertainty (allocation, subsidies) is not resolved, but high (0.70–0.84) in the scenario, where no regulatory uncertainty exists (**Table 9**). A higher value for emission allowance somewhat increases the correlation of the wind power plant and hydro power plant returns. The impact on other correlations depends on the scenario.

Table 8. Sensitivity analysis in the „High, unpredictable allowance price„-scenario with „Correlations"

Technology	Pessimistic[1]	Base-case	Optimistic[2]
CCGT	-11% (9.3%)	-2% (13 %)	+6% (8.8%)
Wind	-57% (1.4%)	-42% (4.5%)	+3% (2.6%)

[1]CCGT: auction after 2012, Wind: certainty about subsidy removal, no investment subsidy
[2]CCGT: free allocation forever, Wind: full-load hours: 3,000 hours, investment subsidy 30%, subsidy maintained

Table 9. Correlations of project returns in different scenarios.

Correlation of project returns	No emissions trading	"Low well-predictable allowance price"	"High unpredictable allowance price"	"High unpredictable allowance price", Optimistic[1]
CCGT-Wind	0.16-0.18	0.17-0.19	0.15-0.24	0.79-0.83
Wind-Hydro	0.18-0.23	0.24-0.28	0.26-0.28	0.75-0.79
CCGT-Hydro	0.56	0.52-0.61	0.44-0.59	0.70-0.84

[1]See Table 8

The average error in the result correlations was about ±0.14 in the "Correlations" -scenario", and ±0.02 in the "No correlations"- scenario.

CONCLUSIONS

This article has explored the impact of emissions trading on the risk and return of three power generation technologies through hypothetical case-studies in Finland. The model runs suggest that the EU ETS increases the expected return of all three power plant technologies due to the higher market price of electricity and the free allowances. The increase in risk compared to the expected return is significant only in the case of the CCGT.

With the data used here, the EU ETS can increase the expected return of CCGT and off-shore wind power investment enough to make them economically viable, but only in the most favorable scenario. This is contrast to Laurikka and Koljonen (2005), who studied viability of a CCGT with a stochastic model using a constant fuel price. The positive correlation applied here changed the outcome.

Investment in an existing hydropower plant portrays as a "high-profit, low-risk" investment within the EU ETS with the data used. Such opportunities can obviously be expected to be rare in competitive markets, in particular as opportunities for green-field hydropower in Europe are small. The prices are therefore likely to adapt. Combined cycle gas turbines seem to be "negative-to-low-profit, high-risk" investments, and off-shore wind power a "negative-to-low-profit, low-risk" investment. Off-shore wind power is viable only in good wind conditions with subsidies.

Regulatory certainty concerning allocation of allowances increases (free allocation) or decreases (auction) expectations on profit for CCGT, and somewhat decreases the total risk. The total risk of a CCGT grows within an emissions trading scheme also through higher volatility of market prices of electricity, gas and emission allowances. Similarly, regulatory certainty concerning wind power tax subsidy decreases or increases profit expectations. It is however not significant for the total risk.

Opportunities for portfolio diversification with the technologies studied are low, since the low correlations in **Table 9** are caused by the regulatory uncertainty. Unless the regulatory uncertainty is resolved positively, the expected returns of CCGT and off-shore wind power fall below zero, and the technologies cannot belong to an efficient portfolio. The high correlation is caused by the market prices of electricity and emission allowance that affect all the technologies.

I have assumed that electricity producers are not penalized for potential windfall profits, i.e. there is no increase in the additional tax, T, for wind and hydro power due to emissions trading. Such a tax would obviously reduce the expected return on investment. I further assumed that hydro power and CCGT investments were idealized assuming perfect prediction and no start-up or shut-down costs. Taxation was not analyzed in detail, and technical risks were ignored. All three technologies were assumed to share the same systematic risk. It was also presumed that the systematic risk is not significantly affected through the introduction of emissions trading. For a power capacity investment, the correlation of the value of the asset with the market portfolio is difficult to determine, since traded twin securities are hard to find. Validity of this last assumption should be paid more careful attention in particular in situations, where the price of allowances becomes very high.

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