RISK AND RETURN FOR INVESTMENTS IN PETROLEUM VERSUS RENEWABLES

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1. Overview

Investment in renewables is to a large extent undertaken by private companies. Thus, risk and return on investment is essential for project sanctioning. Uncertainty raises the cost of capital and discourages investment (Stern, 2007, p. 365). Jaraite and Kazukauskas (2013) state that this fact often is ignored in the literature. They refer to the discussion on the investment effect of feed-in tariffs versus tradeable green certificates and find that existing studies mainly are analytical theoretical or modelling studies that do not discuss the effect on company profitability. They argue for more empirical research that addresses company risk, e.g. research that account for the fact that feed-in tariffs are less risky for companies than tradeable green certificates. With the former, companies have a guaranteed product price, whereas for the latter they face electricity price risk and risk related to the prices of the green certificates. Aguirre and Ibikunle (2014) also refer to scarcity of empirical research relating to renewable investments and policy variables.

The transition to energy with low carbon emission requires large investments, because green technologies such as solar panels and wind turbines are capital-intensive (Johnsen and Lybecker, 2009). The pace of green capital accumulation has accelerated in recent years, led by economies of scale, technological progress, and strong public support (Eyraud et al., 2013). According to the authors, feed-in tariffs are particularly found to foster green investments, with green investments being two to three times larger in countries adopting such schemes. This is not surprising, given the risk reduction for the investors. Lower risk may also allow for higher level of debt financing.

Using world sector indexes, we compare risk and return on companies undertaking petroleum investments and companies making investments in renewables. To the extent that renewables projects have output with regulated output prices, e.g., feed-in tariffs, risk is often perceived lower than for petroleum investments relying on volatile oil and gas prices. If costs in the petroleum sector were stable over time, the project risk would be very high. However, risk is reduced by fact that costs are counter-cyclical. When prices go down, so do the costs, thus reducing the risk.[1] Thus, it is vital to account for the cyclicality of the petroleum industry to understand its risk. To compare the two investment categories, therefore, we need a time span that covers at least a full business cycle. By analyzing data from 2008 to 2019, we meet this criterium.

2. Methods

Our analysis relies on conventional methods of analysing the risk return relationship, using the capital asset pricing model and the Beta-estimate as the determinant for differences in risk adjustments.

Using historic data downloaded from investing.com, Beta-calculations of various investment portfolios are made in order to analyse the Oil and Gas return and required return as compared to that of New Energy producing companies. Our index for the petroleum sector includes both oil companies and the supply industry. After the oil price collapse in 2014, costs have come down considerably and the oil price has increased. Thus, profitability in the oil companies is restored but large parts of the supply industry still struggle with overcapacity, high debt and low profitability.

We analyse the following investment portfolios:

[1] Pro-cyclicality of petroleum costs has several channels, e.g., when the oil price goes down, project cost control goes up (Dahl et. al, 2017), drilling speed increases (Osmundsen et. al 2010, 2012), and rig rates fall (Osmundsen et. al 2015; Skjerpen et. al, 2018).

The MSCI ACWI is a market capitalization weighted index designed to provide a broad measure of equity-market performance throughout the world. The MSCI ACWI is maintained by Morgan Stanley Capital International (MSCI) and is comprised of stocks from 23 developed countries and 24 emerging markets. This portfolio is used as the proxy for the "Market portfolio".

The MSCI ACWI Energy Index includes large and mid-cap securities across 23 Developed Markets (DM) and 26 Emerging Markets (EM) countries. All securities in the index are classified as Energy as per the Global Industry Classification Standard (GICS®). The industry weights in figure 2.1 show that this is an "Oil and Gas" Index.

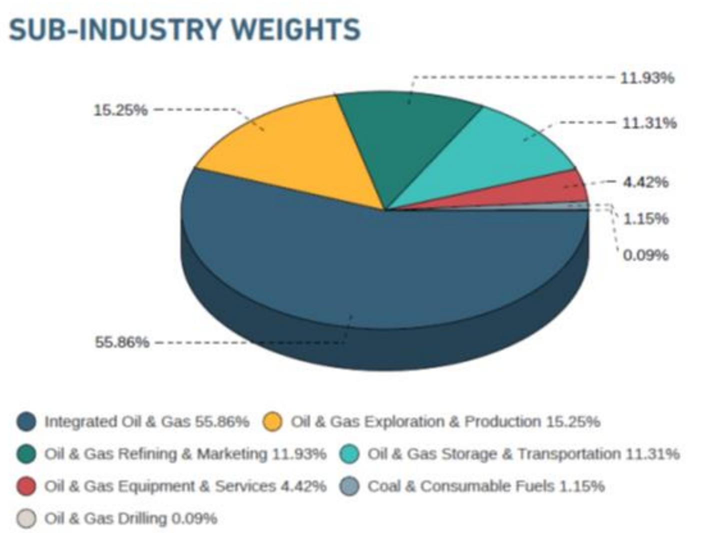

Figure 2.1: Sub-Industry weights in MSCI ACWI Energy Index

For "Alternative Energy" we examine the two Ardour portfolios "Alternative Energy Liq." and "Solar Energy". The Ardour Global Alternative Energy Indexes^{SM} are designed to serve as fair, impartial and transparent measures of the performance of the Alternative Energy Industry. The Liquid index consists of shares which are considered to be more traded in the market (i.e. continuously better reflect the market price). The Solar Energy Ardour consists of shares that are mainly in the Solar Energy industry. For comparison we also show the Bloomberg Gold Index.

Finally, the economics of some German offshore wind projects from 2010 to 2018 are examined using available data and our evaluation of required rate of return.

3. *Results-The return*

We find that due to negative returns in the supplier industry, the return of the Oil and Gas portfolio has been a negative around 20% in the period from 2008 to January 2019, while much worse for Alternative Energy Liq.-Ardour (-40%) and a dismal -90% for the Solar Energy Ardour. The return of the portfolios from 2008 to April 2019 using market data is presented in figure 3.1.

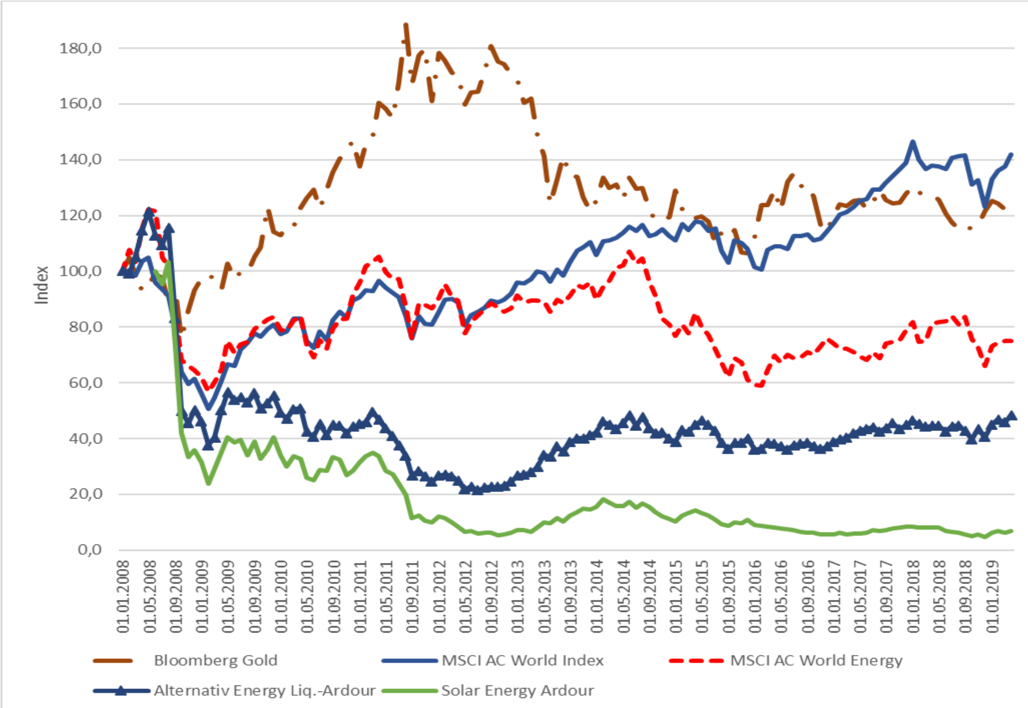

Figure 3.1: Return on investment portfolios from 2008 to January 2019.

4. *Results-The CAPM Beta-risk*

The Beta-risk (CAPM, Sharpe, 1964) is calculated from the monthly return of the portfolios. By using the monthly return we should offset the lower liquidity of the companies in the alternative energy group (due to low market value and less trading). The Beta (leveraged) risk for three different periods - the total period, the first five-year period, and the last five- year period - are presented in table 4.1. The Beta is given by

$$\beta_i = \frac{Kov(r_i, r_m)}{Var(r_m)}), \qquad 4.1$$

where r_i, is the return of an index portfolio and r_m is the return of the market portfolio.

Index Name	*Beta 2008-2019*	*Beta 2008-2013*	*Beta 2014-2019*
Bloomberg Gold	0,16	0,21	-0,03
MSCI ACWI Energy	1,07	1,03	1,15
Alternative Energy Liq.-Ardour	1,42	1,48	1,20
Solar Energy-Ardour	2,00	2,10	1,63

Table 4.1: Calculated leveraged Betas for investment portfolios based on monthly returns

We examine the Betas in further detail, looking at the Alternative Energy Liquid portfolio and it's listed betas in order to compare with the Beta calculated based on monthly returns . Table 4.2 gives an overview of these companies. Their share in the Index, the listed Beta and the weighted beta in the portfolio.

Alternative Energy Liq.-Ardour		% Index	Beta	Beta%	Description of business
VESTAS WIND SYSTEMS AS	Denmark	9,3 %	1,2	0,11	Development of wind power plants and service
AMETEK INC	United States	9,0 %	1,2	0,11	Electronic instruments
MICROCHIP TECHNOLOGY INC	United States	9,0 %	1,4	0,13	Semiconductor
EATON CORP PLC	United States	8,9 %	1,4	0,13	Electric and hydraulic components
TESLA, INC	United States	8,8 %	0,6	0,05	El cars and batteries
CREE INC	United States	4,9 %	0,8	0,04	LED products
NIBE INDUSTRIER AB B	Sweden	4,7 %	1,2	0,06	Producing heating systems
FIRST SOLAR INC	United States	4,2 %	1,3	0,05	Provide Photovoltaic solar systems
Siemens GAMESA renewable energy SA	Spain	3,5 %	1,0	0,04	Wind-producing and operating, also electric equipment
VERBUND AG	Austria	3,4 %	0,8	0,03	Hydropower and wind and Austrian Grid
ENERSYS	United States	2,9 %	1,5	0,04	Industrial batteries
ORMAT TECHNOLOGIES	United States	2,9 %	1,2	0,03	Geothermal and waste heat
KURITA WATER INDUSTRIES	Japan	2,8 %	0,9	0,02	Water treatment-not energy
CHINA LONGYUAN POWER GROUP	China	2,5 %	0,9	0,00	Coal and wind power
NORTHLAND POWER INC,	Canada	2,4 %	0,7	0,02	Gas, biomass, wind and solar
COVANTA HOLDING CORP	United States	2,2 %	1,4	0,03	Waste energy and waste processing
POWER INTEGRATIONS INC	United States	2,1 %	1,2	0,03	Power converter equipments
FRANKLIN ELECTRIC CO	United States	2,0 %	1,3	0,03	water and fuel pumping systems
ESCO TECHNOLOGIES INC	United States	1,9 %	1,0	0,02	Products for fluid flow, utility and packacking
ITRON INC	United States	1,7 %	1,2	0,02	Electric , gas and water utility solutions
BADGER METER INC	United States	1,7 %	0,8	0,01	Flow and control solutions
HUANENG RENEWABLES CORP LTD,	China	1,5 %	1,1	0,02	Wind power and solar power generation
COSAN LTD	Brazil	1,5 %	1,4	0,02	Gas, railway, energy and lubricants
SUNRUN INC,	United States	1,2 %	0,5	0,01	Recidential solar systems
CANADIAN SOLAR INC	Canada	1,1 %	2,3	0,02	Producing solar systems and generating electricity
GCL-POLY ENERGY HOLDINGS LTD,	China	1,0 %	1,2	0,01	Producing solar (polysilicon and wafers)
RENEWABLE ENERGY GROUP INC	United States	0,9 %	1,2	0,01	Biomassbased disel
XINJIANG GOLDWIND SCI & TECH-H	China	0,8 %	1,1	0,01	Manufacturing of windturbines and service of wind farms
JINKOSOLAR HOLDING CO LTD	China	0,7 %	2,2	0,02	Producing solar (photovoltaic)
VICOR CORP	United States	0,5 %	0,8	0,00	Power systems
		100 %		1,1	

Table 4.2: Ardour-Alternative Energy Liquid portfolio Beta

The Alternative Energy Liquid portfolio company Betas, based on quoted market Betas (Investing.com), the portfolio weighted average is 1.1. This is very close to the Betas calculated for the period 2014-2019 using monthly returns (0.1 lower).

$$\beta_i = \sum_{j=1}^{M_i} w_{ij}\beta_{ij} \qquad 4.2$$

where Bi is the Beta of portfolio i, w_{ij} is the relative market value of company j in portfolio i and B_{ij} is the Beta of company j in portfolio i.

For comparison of pure business risk with respect to Beta, the leveraged Betas need to be adjusted for different levels of debt. The debt level is much higher in Green and Renewable Energy than in Oil and Gas, as shown by Table 4.3. The tax level for Oil and Gas however, would not be considered that of a normal year in the oil and gas E&P industry since it includes a lot of losses from companies in the supply industry and since taxes generally are much higher for producing companies throughout the world due to resource rent tax.

Industry Name	***Number of firms***	***D/E Ratio***	***Effective Tax rate***
Green & Renewable Energy	189	90 %	12 %
Oil/Gas (Production and Exploration)	852	57 %	4 %

Table 4.3: Debt equity Ratio and Effective Tax rate. Damodaran 05.01.2019.
http://people.stern.nyu.edu/adamodar/New_Home_Page/data.html

We therefore assume an effective tax rate of 60% when estimating the unlevered Beta for the E&P companies. Assuming a Green and Renewable Energy debt percentage of 90% and a 12% tax level for New Energy producing companies, indicate that the leveraged Beta of 1.3 corresponds to an unleveraged Beta of 0,7).[2] This is somewhat lower than for the E&P companies using Debt/equity of 57% and effective tax of 60%. This implies a Beta-value of 0.9. For companies with fixed price contracts the Beta would be much lower. (Scatec Solar is an example of this with leveraged Beta of 0.4 which would indicate about 0.3 unleveraged).

Index Name	*Beta 2008-2019*	*Beta 2008-2013*	*Beta 2014-2019*
MSCI ACWI Energy	0,9	0,8	0,9
Alternative Energy Liq.-Ardour	0,8	0,9	0,7
Solar Energy-Ardour	1,1	1,2	0,9
Alternative Energy Liq.(listed betas)			0,6

The Alternative Energy Liq.-Ardour is 0,6-0,7 (2014-2019), that is 0,3-0,2 lower than for the Oil and Gas producing companies. It remains to be seen whether the unleveraged equity Betas will remain at the same level in the future with greater liquidity, higher market value of New Energy companies, and market exposed contracts in the New Energy Industry.

5. *The economics offshore wind projects*

The projects

We have analysed the main German offshore wind projects that were commissioned from 2010 to 2018. For comparison we include the floating offshore wind project Hywind Tampen in Norway and the proposed Empire Wind offshore New York. All the data is based on market information (Wikipedia and companies).

Alpha Ventus, is a wind farm owned by Deutsche Offshore-Test feld und Infrastruktur-GmbH & Co. KG, a joint venture of EWE (47,5%), E.ON (26.25%), and Vattenfall (26.25%). It consists of twelve turbines, all with capacity of five megawatts. There are six Adwen AD 5-116 (former Areva Multibrid M5000 turbines and six REpower 5M turbines. Turbines stand in 30 m of water and are not visible from land, however they are barely visible from Norderney's lighthouse, and easily from the island of Borkum.The REpower turbines are installed onto jacket foundations (OWEC Jacket Quattropods) by the crane ship Thialf and Adwen turbines are installed onto tripod-style foundations by the jack-up barge Odin. In May 2010, two Multibrid generators went off service due severe overheating in their gearboxes. Due to delays, the cost of the project grew from 190 million to 250 million euro (US$270 to $357 million), or 4200 €/kW (6000 $/kW).[6][7]

BARD Offshore 1 is a 400 megawatt (MW) North Sea offshore wind farm with 80 BARD 5.0 turbines. Construction was finished in July 2013 and the wind farm was officially inaugurated in August 2013. The wind farm is located 100 kilometres (60 miles) northwest of the isle Borkum in 40-metre (130 ft) deep water. Laying of cables to connect the wind farm started on 23 July 2009. The 200 km connection is the longest of its kind in the world. It is also the first connection of an offshore wind park realized as HVDC-transmission. Construction of the wind turbines began in March 2010. The first turbine became operational at the beginning of December 2010. Construction was assisted by the purpose-built Wind Lift

[2] Beta Unleveraged=Beta Leveraged/(1+(1-t)xD/E), where t is the tax rate, D is debt and E is equity.

1 barge / platform, which placed the 470-ton, 21 meter foundations on the sea bed. The project run into serious and unclear problems, including being three years behind schedule and, at a cost of €3 billion, significantly over budget. The farm was supposed to go online in August 2013, but a series of setbacks, including a fire at a transmission station in March 2014, have delayed its activation. BARD went bankrupt in November 2013.

Borkum Riffgrund 1. The 277MW Borkum Riffgrund 1 offshore wind farm in the North Sea, 55 km from the north-western coast of Germany. The wind farm is operated and maintained by Denmark based Ørsted (previously DONG). The estimated investment on the offshore power project was €1.25billion. Offshore construction of the wind farm began in 2013 and commercial operations started in October 2015. The wind farm is expected to power approximately 320,000 German households.

Gode Wind 1 & 2, are offshore wind farms located north-west of Norderney in the German sector of North Sea. They are owned by Ørsted. On 18 November 2013, DONG announced the decision to invest €2.2 billion in Gode 1 & 2. Bladt Industries will supply the foundations, with a diameter of 6 meters. Gode 1 & 2 consist of a total of 97 Siemens SWT-6.0-154 turbines generating up to 582 MW. The projects were officially commissioned in June 2017.

Arkona Wind Park. The Arkona wind farm is located 35 kilometers northeast of the island of Rügen. The wind farm has a capacity of 385 megawatts and can supply approximately 400,000 households with renewable energy. The investment was €1.2 billion. The partner companies were able to connect the Arkona offshore wind farm to the grid on time and at lower costs than originally calculated. It took only one year from the first ramming to the first electricity feed-in. Rarely before has an offshore project been completed so quickly. The reasons for the success of the fast completion are the detailed planning and the professionally implemented construction process.

Hywind Tampen (Norway). Hywind Tampen is an 88 MW floating wind power project intended to provide clean electricity for the Snorre and Gullfaks offshore field operations in the Norwegian North Sea. It will be the world's first floating wind farm to power offshore oil and gas platforms. The partners of the Snorre and Gullfaks fields reached a final investment decision (FID) in October 2019 and awarded key contracts for the NOK 5 billion project. The project is scheduled to commence operations in the second half of 2022. The Hywind Tampen wind farm will be operated by Equinor, which is also the operator of Snorre and Gullfaks offshore fields.

Empire Wind (New York); Equinor's 816 MW Empire Wind facility will be made up of between 60 to 80 wind turbines, according to the business. It will cover an area of 80,000 acres and be located southeast of Long Island. Total investments in the facility will amount to around $3 billion, and it will be able to power more than 500,000 homes.

The project investment and installed capacity figure for the projects are summarised in Table 5.1.

Name	Capacity (MW)	Turbines	Commissioned	Capex	Owner	CAPEX per MW Mill euro
Alpha Ventus	60	6 × Multibrid M5000, 6 × REpower 5M	2010	€250 million	EWE E.ON Vattenfall	4,2
BARD Offshore 1	400	80 × BARD 5.0	2013	€2.9 billion	Ocean Breeze Energy	7,3
Borkum Riffgrund I	312	78 × Siemens SWT-4.0-120	2015	€1.25 billion	DONG, Kirkbi, Oticon	4,0
Gode Wind 1 & 2	582	97 × Siemens SWT-6.0-154	2017	€2.2 billion	DONG Energy	3,8
Arkona Wind Park	385	60 × Siemens-Gamesa SWT-6.0-154	2018	€1.4 billion	Equinor ASA, E.ON Energy Projects GmbH	3,6
Hywind Tampen	88	11 Siemens Gamesa-8mw	2019	€ 500	Offshore partners	5,7
Empire Wind	816		2024	€ 2 700	Equinor	3,3

Table 5.1: Project investments and capacity installed

If we exclude the BARD offshore project (because of the large investment overruns), the CAPEX per MW installed have been reduced from 4,2 million Euro to 3,6 million Euro from Apha ventus in 2010 to Arkona Wind Park in 2018. This is a 12,7% reduction in installed capacity per MW. If we use the expected investment and capacity figure from Empire wind compared to that of Alpha Ventus, the reduction is 20,6%. It is perhaps somewhat unexpected that the cost reduction has not been larger.

Project operating cost and annual capacity utilisation

The IEA (2018) specifies an OPEX cost of offshore wind projects that corresponds to about 2-2,5% of IEA estimate of investment cost (3459 Euro/kw = 3,5mill Euro/MW). We will assume 3% of investment cost for the two first projects (Alpha ventus and bard Offshore), 2,5% for the two projects commissioned from 2015-2017, and 2% for the later projects (except Hywind where we assume 3%) .

There is a wide range of capacity utilisation reported (30%-55%). It depends on numerous factors (IEA 2018), of which wind conditions are probably the most important. We will use a 40% utilisation factor throughout the generating life of the project. A percentage change in the utilisation factor gives a similar percentage change in the breakeven figure for the project.

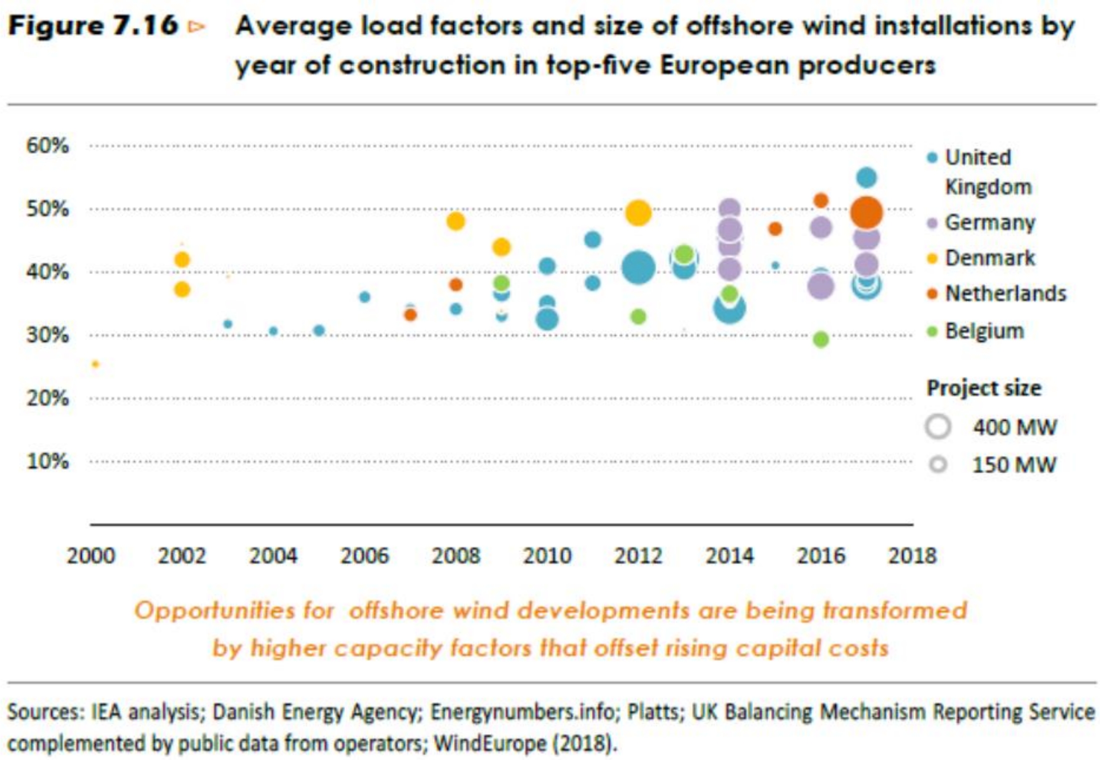

Figure 5.1: Average yearly capacity utilisation

Project Economics

We make simplified assumptions and use the investment figures as a one year investment, one year before electricity production commences and continues for 20 years. We use the operating cost and average annual capacity utilisation (40%) as specified and include a 20% of investment removal cost in year following last year of electricity production. For comparison reasons the economics is calculated as if the projects where new projects with investments in 2019 and electricity generation from 2020.

The German fixed price contract has established an applicable tariff of 15,4 ct/kWh as initial value for remuneration, which is granted for a period of 12 years. Alternatively operators may opt for the so-called "Stauchungsmodell" (acceleration model). With this model the operator has the opportunity to receive an initial remuneration of 19 ct/ kWh for a reduced period of 8 years, provided that the offshore WT is commissioned before 2020. The basic tariff for offshore WT following the increased initial remuneration remains unaltered 3,9 ct/kWh until the maximum remuneration period (20 years plus year of commissioning) is reached. As before, for projects which are at least 12 nautical miles away from the coast and/or in waters deeper than 20 m, the period for the increased initial remuneration is extended, depending on the actual site conditions. The German offshore wind farms are built quite far from shore compared to projects in other countries, to keep them out of sight from coastal dwellers. New installations are built an average distance of 74 kilometers from the coast and at a depth of 33 metres, according to the BWE and therefore the projects meet the extension requirement. A 10-year period of 19 ct/kwh (nominal) is therefore assumed for the fixed subsidy price, followed by 3,9 ct/kwh (nominal) the next 10 years. As market price we assume Norpool electricity price with an expected price of 35 Euro/Mwh.

For the discount rate we assume a market risk premium of 7,4% (Damodaran, 2019). This risk premium is in a historically setting very high but probably reflects the current market situation where also the interest rates are very low. Therefore, with this market risk premium, the 0,2-0,3 difference in Beta-value estimated in section 4 as compared to Oil and Gas (MSCI ACWI Energy), would indicate approximately a 1,5%-2% lower return requirement based on systematic equity risk only. The use of company data for estimation of a project discount rate is of course an approximation, and more so when the companies are not involved solely with electricity generation. Using company debt ratios and cost of debt financing would be even more difficult since it would relate to a specific company. Consequently, we simplify assuming a nominal rate of 8,5% which is 1,5% lower than the discount rate that WoodMackenzie (2018) uses for oil and gas exploration valuation. When calculating the project NPVs using the fixed subsidised price, we assume a 6% nominal discount rate.

Our analysis indicates that German offshore wind projects, except BARD, give a sufficient return with the fixed price agreement. For the wind projects to be profitable, without a fixed price, and at the current market price for electricity (Norpool), the cost of the latest commissioned (2018) offshore wind projects would have to decrease by an additional 60%. This demonstrates how much impact the rate of return requirement and the level of the fixed price contract have for project profitability assessments in an industry with large front-end investments.

		Nominal rate 8,5%	Nominal rate 8,5%	Nominal IRR	Nominal rate 6%	Nominal IRR
Windfarm	Comissioned	B/E Euro/Mwh	NPV (Norpool)	(Norpool)	NPV (fixed price)	Fixed price
Alpha Ventus	2010	130	-230	NA	7	6,7 %
BARD Offshore 1	2013	230	-3400	NA	-1500	-4,0 %
Borkum Riffgrund I	2015	120	-1130	NA	400	11,6 %
Gode Wind 1 & 2	2017	110	-2000	NA	900	13,0 %
Arkona Wind Park	2018	100	-1100	-6,7 %	780	15,0 %
Hywind Tampen	"2021"	160	-480	NA	NA	NA
Empire Wind	"2024"	100	-2100	-5,3 %	?	?

Table 5.2: Summary economics for the projects (*All NPV's in Million Euro)

In Figure 5.2, breakeven prices of German offshore wind installation projects are compared with the common feed-in tariff. As seen by the blue line, the feed-in tariff is fixed at the high 1,9 euro/Kwh for the first 10 years of the project, after which the investors receive the low feed-in tariff of 39 cents/kwh. The Nordpool price is fluctuating. In the diagram we have used an expected Norpool price of 35 Euro/Mwh, A given project is profitable, if the net present value of the output price is higher than the breakeven price. As seen from the results in Table 5.2, the offshore wind projects should give sufficient return under the fixed price regime even if our somewhat optimistic and simplified assumptions regarding investment period (1 year) and operating cost will not be met. The three projects commissioned from 2015 to 2018 have nominal internal rate of return above 11% in our calculations with the German feed-in tariff. Note that projects are not without risk, the IRRs have varied from -4% to 15%.

The diagram illustrates the challenge to develop new offshore windmills if the feed-in tariff is abolished and investors only face the Nordpool price. The breakeven prices are still much higher than the market price of electricity. As seen from the breakeven price of 100 Euro per Mwh for the latest offshore wind projects, to meet the market price assumption at our expected Norpool price of 35 Euro/Mwh, the investment costs have to be reduced by an additional 60% from the "2018-2019" level.

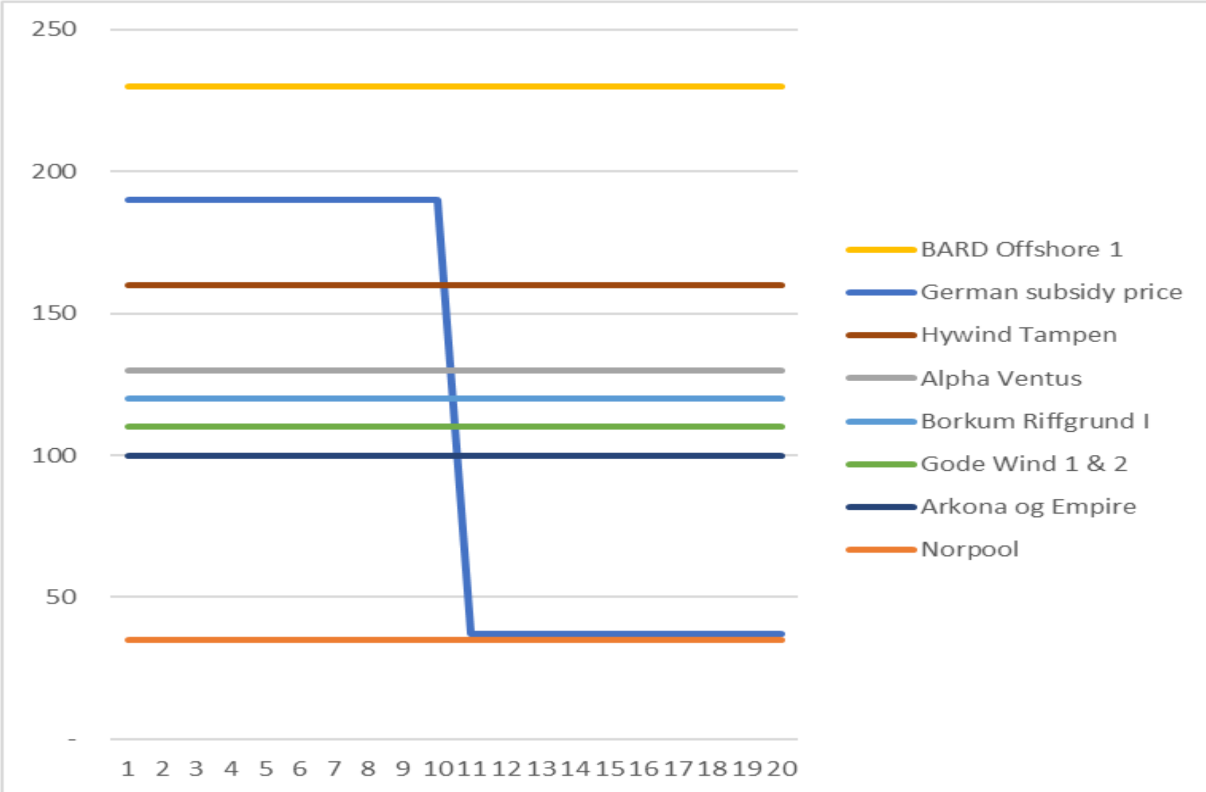

Figure 5.2: The annual German subsidy price, project breakeven values and expected market price (Norpool) (Real Euro /Mwh).

One crucial assumption here is the average capacity utilization (40%). A percentage change would indicate a similar percentage change in the breakeven price, i.e. if capacity utilization is increased by 10%, the breakeven-price is reduced approximately by 10%.

6. Conclusions

Our analysis based on historic data indicates that the required rate of return of equity for new energy generating companies that face price risk is in the lower range of oil and gas producing companies. The unlevered Beta estimate is only 0.2 below that of oil and gas.

Renewables has up to now have typically had favourable regulation that secured guaranteed prices, thus lowering the risk considerably. Feed-in tariffs, allowing the companies to take up loans with security in revenue from fixed prices, have enabled high debt ratios. Cost reductions through technological progress, economies of scale and low interest rates, have made new energy able to compete with fossil fuels in some markets (Eyraud et Al., 2013). Depending on how policies are changed, this would represent a new chapter for this industry. The prevalent current policy is that there is an auction for the level of fixed price feed in tariff. Another possible scenario would be that feed-in tariffs are maintained, but the companies pay auction fees for the right to supply energy at a politically determined feed in tariff. This would increase the risk somewhat by introducing an up-front payment, but the main risk structure would be unchanged. Another solution, that perhaps is more likely in the long term, is that feed-in tariffs are abolished. The companies would then be exposed to market price risk. The fact that higher risk demands a risk premium also for electricity is confirmed by Jaraite and Kazukauskas (2013) that find that companies operating in countries that have implemented tradeable green certificates have a higher rate of return than companies producing under feed-in tariff systems. A deregulation that made companies face price risk would probably also make high debt financing more difficult, resulting in lower gearing.

As seen from our offshore wind economics calculation, the cost of offshore wind must be reduced by an additional 60% to meet the level of expected variable market price for electricity. Calculations that conclude that new offshore windmills are profitable at current market prices is not supported by our analysis and must be of a socio-economic nature, applying a much lower rate of return requirement than what is demanded by private investors.

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Appendix 1: Monthly average prices

	MSCI ACW Index	MSCI ACWI Energy	Alternative Energy Liq.-Ardour	Solar Energy-Ardour	Bloomberg Gold
01.01.2008	369,93	292,97	3070,73		124,25
01.02.2008	370,41	315,04	3045,75		130,54
01.03.2008	363,99	302,71	3226,94		122,77
01.04.2008	383,3	339,13	3521,09		115,25
01.05.2008	387,75	358,35	3730,94		118,21
01.06.2008	355,4	355,71	3465,16	5526,38	123,08
01.07.2008	345,75	307,34	3359,43	5264,8	121,05
01.08.2008	337,61	297,99	3550,87	5705,89	109,57
01.09.2008	294,79	249,86	2557,08	4017,49	115,56
01.10.2008	236,11	199,8	1532,78	2321,85	94,22
01.11.2008	220,05	193,84	1395,73	1847,82	107,17
01.12.2008	227,68	188,77	1544,14	1986,23	115,71
01.01.2009	208,02	181,99	1419,03	1735,06	121,27
01.02.2009	187,17	166,35	1155,37	1312,17	123,11
01.03.2009	202,04	176,25	1239,92	1603,01	120,54
01.04.2009	225,24	190,35	1540,14	1947,53	116,14
01.05.2009	246,69	219,6	1738,54	2240,63	127,48
01.06.2009	244,9	207,26	1650,36	2131,1	120,6
01.07.2009	266,14	216,49	1680,66	2189,53	123,91
01.08.2009	275,1	218,71	1622,36	1874,51	123,61
01.09.2009	287,23	232,15	1725,5	2152,65	130,85
01.10.2009	282,59	236,77	1557,65	1813,71	134,88
01.11.2009	293,67	242,46	1619,69	1991,09	153,09
01.12.2009	299,44	245,15	1698,24	2229,6	141,94
01.01.2010	286,33	231,28	1515,04	1877,51	140,16
01.02.2010	289,5	230,96	1441,34	1656,86	144,7
01.03.2010	307,4	241,61	1551,8	1858,44	143,97
01.04.2010	307,35	246,02	1561,85	1818,31	152,52
01.05.2010	277,17	215,97	1300,38	1429,58	156,72
01.06.2010	268,25	202,77	1247,27	1381,66	160,7
01.07.2010	289,75	220,51	1388,72	1589,43	152,21
01.08.2010	279,06	211,14	1266,49	1576,23	160,75
01.09.2010	305,16	232,26	1379,43	1843,89	168,37
01.10.2010	315,95	242,26	1368,9	1791,61	174,54
01.11.2010	308,38	243,01	1288,9	1489,11	177,93
01.12.2010	330,64	267,58	1357,8	1578,47	182,46
01.01.2011	335,58	280,99	1386,05	1734,79	171,07
01.02.2011	344,82	298,12	1410,59	1856,23	180,73
01.03.2011	343,64	302,56	1524,47	1921,81	184,38
01.04.2011	356,9	308,03	1435,86	1853,37	199,29
01.05.2011	347,9	292,16	1337,59	1567,51	196,62
01.06.2011	341,82	284,49	1252,67	1511,97	192,27
01.07.2011	335,9	285,07	1155,62	1309,14	208,42
01.08.2011	310,62	255,95	1043,32	1088,71	234,04
01.09.2011	280,64	222,22	824,71	639,76	207,29
01.10.2011	310,43	259,87	872,77	692,25	220,43
01.11.2011	300,45	257,6	810,25	590,11	223,33
01.12.2011	299,51	254,09	754,21	542,74	199,92
01.01.2012	316,65	264,93	817,04	660,45	221,68
01.02.2012	331,93	279,4	834,18	631,74	217,97
01.03.2012	333,3	265,6	813,65	540,92	212,61
01.04.2012	328,67	262,39	761	469,94	211,63
01.05.2012	297,98	227,89	666,8	356,51	198,63
01.06.2012	312,11	239,36	699,95	374,46	203,71
01.07.2012	316,02	246,81	655,83	320,31	204,42
01.08.2012	322,14	253,11	691,87	346,74	213,66
01.09.2012	331,58	259,78	697,32	350,63	224,59
01.10.2012	329,07	255,4	694,85	293,42	217,65
01.11.2012	332,64	250,57	711,37	303,88	216,56
01.12.2012	339,75	253,87	753,18	353,19	211,89
01.01.2013	355,1	267,61	816,82	404,29	209,87
01.02.2013	354,43	260,52	832,19	403,15	199,28
01.03.2013	360,06	261,82	855,23	356,71	201,24
01.04.2013	369,42	261,94	915,26	453,36	185,65
01.05.2013	367,19	261,05	1048,68	555,51	175,5
01.06.2013	355,81	250,01	1026,41	527,16	154,17
01.07.2013	372,49	262,82	1139,86	634,08	165,13
01.08.2013	363,98	259,89	1085,54	566,96	175,59
01.09.2013	382,07	267,7	1188,04	693,26	166,9
01.10.2013	397,11	278,68	1228,75	757,12	166,48
01.11.2013	402,05	275,92	1231,79	815,2	157,13
01.12.2013	408,55	281,29	1264,78	800,26	151,08

	MSCI ACW	MSCI ACWI	Alternative Energy Liq.-	Solar Energy-	Bloomberg Gold
01.01.2014	391,92	262,93	1294,55	861,37	155,72
01.02.2014	410,13	276,65	1413,83	1006,68	166
01.03.2014	411,02	282,58	1379,72	944,44	161,22
01.04.2014	414,09	296,86	1334,93	871,86	162,74
01.05.2014	421,53	299,14	1394,57	873,33	156,43
01.06.2014	428,75	313,31	1485,4	952,9	165,97
01.07.2014	423,04	301,01	1367,99	835,6	160,88
01.08.2014	431,55	306,86	1468,52	917,71	161,46
01.09.2014	416,85	282,25	1343,07	852,41	151,95
01.10.2014	419,45	267,8	1284,01	749,73	146,94
01.11.2014	425,82	243,47	1292,06	668,96	147,32
01.12.2014	417,12	237,26	1223,57	623,94	148,39
01.01.2015	410,33	225,32	1192,31	568,71	160,2
01.02.2015	432,47	236,92	1319,96	681,58	151,92
01.03.2015	424,76	228	1300,15	734,27	148,04
01.04.2015	436,3	249,64	1380,18	791,03	147,94
01.05.2015	434,51	234,84	1423,98	740,76	148,74
01.06.2015	423,51	226,14	1374,81	684,02	146,49
01.07.2015	426,78	210,96	1312,33	606,51	136,63
01.08.2015	396,73	196,96	1177,15	520,26	141,3
01.09.2015	381,65	181,66	1110,75	485,17	139,14
01.10.2015	411,25	201,31	1179,76	553,73	142,41
01.11.2015	407,2	197,47	1178,55	528,71	132,81
01.12.2015	399,36	179,24	1230,31	603,1	132,18
01.01.2016	375,02	173,87	1107,16	504,38	139,14
01.02.2016	371,66	172,51	1111,89	488,87	153,85
01.03.2016	398,26	188,84	1184,69	466,02	153,86
01.04.2016	403,34	204,26	1170,53	454,94	160,69
01.05.2016	402,57	197,14	1138,65	424,25	151,31
01.06.2016	399,29	205,23	1108,03	407,49	164,12
01.07.2016	416,09	201,82	1155,67	401,3	167,78
01.08.2016	416,61	202,49	1166,5	368,38	162,08
01.09.2016	418,43	207,88	1180,95	348,75	162,79
01.10.2016	411,01	205,6	1141,15	343,31	157,35
01.11.2016	413,43	214,18	1109,61	302,38	144,69
01.12.2016	421,84	222,01	1140,74	304,18	141,95
01.01.2017	433,13	216,85	1192,29	318,59	148,93
01.02.2017	444,5	211,59	1217,05	349,92	154,16
01.03.2017	448,87	211,96	1236,68	317,05	153,4
01.04.2017	455,17	207,75	1279,7	321,44	155,49
01.05.2017	463,79	203,5	1315,08	327,72	155,92
01.06.2017	465,09	199,99	1332,1	351,89	151,87
01.07.2017	477,58	207,56	1351,94	389,03	154,77
01.08.2017	478,41	201,34	1306,38	383,51	160,7
01.09.2017	486,88	217,09	1342,16	396,16	156,15
01.10.2017	496,62	219,06	1396,11	437,86	154,41
01.11.2017	505,44	220,51	1334,39	452,59	154,65
01.12.2017	513,03	230,37	1378,11	465,17	158,59
01.01.2018	541,67	239,68	1425,09	458,14	162,1
01.02.2018	518,08	218,96	1384,16	450,23	159,06
01.03.2018	505,81	220,11	1358,66	453,41	159,48
01.04.2018	509,69	238,16	1368,22	455,18	158,51
01.05.2018	508,77	239,79	1367,76	450,78	156,02
01.06.2018	505,2	240,87	1306,39	372,76	150,02
01.07.2018	519,82	245,63	1360,61	368,2	146,21
01.08.2018	522,88	237,01	1370,26	343,45	143,02
01.09.2018	524,25	244,75	1307,74	317,3	141,78
01.10.2018	484,57	221,66	1220,38	269,4	144,01
01.11.2018	490,86	213,6	1330,6	308,34	144,6
01.12.2018	455,66	193,93	1243,69	261,95	151,12
01.01.2019	491,19	213,95	1379,97	345,82	155,5
01.02.2019	503,48	217,59	1435,45	379,88	154,44
01.03.2019	508,55	219,66	1403,82	347,82	151,6
01.04.2019	524,84	220,15	1483,3	374,44	150,11