HELLENIC OPEN UNIVERSITY

School of Social Sciences

MBA Programme

Postgraduate Dissertation

Financing and valuation of projects in the Renewable Energy sector

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Patras, Greece, September 2021

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To my lovely wife Tina, for her precious love and support

Abstract

Up to now, investments in the Renewable Energy Sources (RES) sector, were performed under a FiT (Feed in Tariff) or FiP (Feed in Premium) incentive scheme, that made their valuation and their financing straight-forward, since their income was easily calculated from the beginning and the only variable was the yield estimation, leading to an easy modeling of the cash inflows.

Newer remuneration schemes such as bilateral contracts as well as participation in the spot market at the Target Model Era to be implemented, import a number of unknown parameters that make modelling more difficult, due to the volatility of the expected remuneration price.

This work examines the various parameters that are included in the financial modeling for valuating or financing purposes, based on the future remuneration schemes to come.

Investments in Onshore Wind Farms and PV (Photovoltaic) stations are examined since they utilize currently prevailing RES technology, with the aim to show whether such investments continue to be both bankable and attractive from an investment opportunity point of view, in order to continue to be main drivers leading to carbon neutrality.

Investments under a FiP supporting scheme are modelled and compared with investments participating in the spot market, with the aim of assessing if the latter may secure bank financing with current market terms, as well as to evaluate whether their financial indicators are within the returns expected by current investors.

Keywords

Renewable Energy Sources, Financial Model

Χρηματοδότηση και αποτίμηση έργων Ανανεώσιμων Πηγών Ενέργειας

Νικόλαος Πατσόπουλος

Περίληψη

Μέχρι τώρα, οι επενδύσεις στον τομέα των Ανανεώσιμων Πηγών Ενέργειας (ΑΠΕ), πραγματοποιούνταν στο πλαίσιο υποστηρικτικών προγραμμάτων όπως σταθερών ταριφών FiT (Feed in Tariff) ή διαφορικής προσαύξησης FiP (Feed in Premium), που έκανε την αποτίμηση και τη χρηματοδότησή τους απλή, καθώς το εισόδημά τους μπορούσε να υπολογιστεί εύκολα από την αρχή και η μόνη μεταβλητή ήταν η εκτίμηση της απόδοσης, που οδηγούσε σε μια εύκολη μοντελοποίηση των ταμειακών εισροών.

Νεότερα μοντέλα αποζημίωσης, όπως διμερείς συμβάσεις, καθώς και συμμετοχή στην αγορά επόμενης ημέρας που θα υλοποιηθεί στα πλαίσια του «Μοντέλου στόχου» (Target Model), θα εισάγουν μια σειρά από άγνωστες παραμέτρους που καθιστούν τη μοντελοποίηση δυσχερέστερη, λόγω της αστάθειας της αναμενόμενης τιμής αποζημίωσης.

Αυτή η εργασία εξετάζει τις διάφορες παραμέτρους που περιλαμβάνονται στο χρηματοοικονομικό μοντέλο για σκοπούς αποτίμησης ή χρηματοδότησης, με βάση τα μελλοντικά μοντέλα αποζημίωσης.

Οι επενδύσεις σε σταθμούς αιολικής ενέργειας και φωτοβολταϊκούς σταθμούς εξετάζονται δεδομένου ότι αποτελούν τις επικρατούσες τεχνολογίες ΑΠΕ, με σκοπό να φανεί εάν τέτοιες επενδύσεις εξακολουθούν να είναι χρηματοδοτίσιμες και ελκυστικές από την άποψη της επενδυτικής ευκαιρίας, ώστε να συνεχίσουν να αποτελούν κύριους παράγοντες που οδηγούν στην ουδετερότητα του άνθρακα.

Οι επενδύσεις στο πλαίσιο ενός προγράμματος στήριξης διαφορικής προσαύξησης FiP μοντελοποιούνται και συγκρίνονται με τις επενδύσεις που συμμετέχουν στην αγορά επόμενης ημέρας, προκειμένου να εκτιμηθεί εάν οι τελευταίες μπορούν να εξασφαλίσουν τραπεζική χρηματοδότηση με τους τρέχοντες όρους της αγοράς, καθώς και να αξιολογηθεί εάν οι χρηματοοικονομικοί τους δείκτες βρίσκονται εντός των αποδόσεων που αναμένουν οι σύγχρονοι επενδυτές.

Λέξεις – Κλειδιά

Ανανεώσιμες Πηγές Ενέργειας, Οικονομικό Μοντέλο

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List of Abbreviations & Acronyms

ARESGO	Administrator of Renewable Energy Sources and Guarantees of Origin
BOP	Balance of Plant
CF	Capacity Factor or Cash flow
CFADS	Cash flow available for Debt Service
CfD	Contract for Difference
CPI	Consumer Price Index
CRES	Centre for Renewable Energy Sources
DSCR	Debt Service Coverage Ratio
DSRA	Debt Service Reserve Account
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EBT	Earnings Before Tax
EIA	Environmental Impact Assessment
ETA	Environmental Terms Approval
EU	European Union
FCF	Free Cash Flow
FiP	Feed-in-Premium
FiT	Feed-in-Tariff
GHG	Greenhouse Gases
HEDNO	Hellenic Electricity Distribution Network Operator
HEnEX	Hellenic Energy Exchange
HV	High Voltage
IDC	Interest During Construction
IPPM	Independent Power Producer Module
IPTO	Independent Power Transmission Operator
IRR	Internal Rate of Return
km	kilo-meters
kV	kilo-Volt
kW	kilo-Watt
kWp	kilo-Watt peak

LCOE	Levelized cost of Energy
LID	Light induced Degradation
LLCR	Loan Life Coverage Ratio
LTC	Loan to Cost
MRA	Maintenance Reserve Account
MV	Medium Voltage
MVA	mega-Volt Ampere
MW	mega-Watt
NPV	Net Present Value
OECD	Organization for Economic Co-operation and Development
OPEXRA	Operational Expenses Reserve Account
PPA	Power Purchase Agreement
PPC	Public Power Corporation
PV	Photovoltaic
RAE	Regulatory Authority of Energy
RES	Renewable Energy Sources
S/S	Substation
SEC	Standard environmental Commitments
SPAA	Sliding Premium Aid Agreement
UHV	Ultra-High Voltage
WACC	Weighted Average Cost of Capital
WF	Wind Farm
WTG	Wind Turbine Generator

1. Introduction

1.1. Developments in the Renewable energy sector

The renewable energy sector in Greece started growing in 1999, after law 2773/1999 allowed the generation of energy from private entities. Up to that time, only demonstration RES projects by PPC or CRES or other institutions were constructed. A boost was given in 2006 when law 3468/2006 offered incentives for the construction of RES projects by investors, by setting a fixed tariff (FiT) scheme, under which each produced MWh of energy was compensated at a predefined value, while renewable energy projects were offered dispatch priority.

The incentive scheme was modified in 2016 with law 4414/2016, which introduced both a FiP incentive scheme, as well as a tender process for the definition of the Reference Price at which RES projects would be remunerated. This was an intermediate framework to prepare the market for a full liberalization, as defined in the Target Model, under EU's third energy package. Further analysis of these schemes takes place in Chapter 3 of this dissertation.

This transition from a solid revenue stream to a volatile compensation scheme from the free market needs to be assessed, since most RES developments in Greece are financed through non-recourse project finance bank loans, which heavily rely on the "forecastability" of the projects' cash flows. Financing organizations used to offer loans with high LTC ratios and low interests, resulting in a low WACC which in return resulted in low LCOEs for the RES investments. The Target model approach exposes RES investments in the free market's uncertainty, which may be mitigated through a long-term bilateral PPA with an energy off-taker. Since such agreements are not yet the norm in the market, this dissertation examines the possibility of financing a RES project within the Target model operating scheme of the spot market and valuates the investment in comparison with a similar under a FiP support scheme, in an effort to guide both investors and lenders into the optimal handling of such ventures.

This research will contribute in the closing of the research gap which appeared from the transition of the FiT/FiP supporting schemes to the free market operating scheme of the Target Model.

1.2. Methodology of approach

In order to examine the effect on the financial and financing indicators of projects that have not secured a long term fixed remuneration price, the following methodology is followed.

Financial models of wind farm and PV investments are drafted assuming investment (CAPEX) and operational costs (OPEX) at currently prevailing levels, as well as produced power remuneration price at the levels of 2020 RAE tender results. The models are examined for a 20-year operation period, while the loan tenor is also assumed for the same period. Main financing indicators such as DSCR and LLCR are calculated, as well as investment indicators such as NPV and equity and project IRRs. These ratios are considered the basis of comparison, since RES projects are currently being financed with them and Lenders as well as investors heavily rely their decision making on them.

The financial models of investments in the future are also drafted, considering the estimated CAPEX and OPEX levels that should be expected in a few years' time. Year 2023 is considered as the starting point, since at that time RAE tenders will be at their final years (2024 is the last estimated tender) and after that, RES power generation from Onshore wind and PV stations will only be remunerated through the spot market or bilateral PPAs. Financing as well as investing indicators are calculated for various loan tenors and operating terms, while an estimated spot market price trend is utilized. Ability of the projects to receive financing is evaluated, as well as viability of the investments, by setting current market thresholds for the calculated indicators.

The value of the assets at every operating year is also estimated, in order to assess the impact of the spot price variation at the project valuation.

1.3. Importance of this research

This research is an effort to examine the impact of the change of the remuneration methodology of RES projects from partly subsidized through a FiP, to unsupported free market participation, in their ability to secure financing, as well as to their attractiveness to potential investors.

The importance of dealing with climate change has long been identified by all countries in the world, leading to a number of agreements with the latter being the Paris Agreement in which a goal of limiting global warming below 2 degrees Celsius, compared to the levels before the industrial era (The Paris Agreement, n.d.), was set. This agreement materialized in country specific action plans, the ones for Greece being the "Long term strategy for

2050", as well as the "National Energy and Climate Plan (NECP) 2030", established in December 2019. The latter has set a number of intermediate policies and action plans to be followed up to 2030, as well as targets, among others in the development of RES and their participation in the energy mix. The gross energy consumption from RES should reach 35%, compared to the 18% it was in 2019, while RES installed capacity should rise from 10,1GW to 19,03GW (Ministry of Environment and Energy, 2019).

Reaching these targets is considered of utmost importance in the path to carbon neutrality, therefore this research aims at supporting this route by investigating the methods of continuing RES projects' successful realization aiming at highlighting the reasons why RES investments in Greece shall continue to be attractive and bankable investment opportunities.

2. Financing and accessing the Investments' value

2.1. Introduction

In order to finance the Renewable Energy project's construction, a Sponsor would evaluate the possible options and select the one that would offer the highest return, while at the same time would decrease his own risks.

Commonly encountered methods of financing project construction, are the company's own funds, bank loans, green bonds, government grants and tax incentives and international assistance programs (Shan, Hwang, & Zhu, 2017). In Greece, a mixed financing scheme is usually encountered, with the Sponsor providing the equity and a commercial bank or a syndication of banks providing the debt, with a project finance loan. Government subsidies were also offered in the past, while the issuing of Company bonds or Green bonds also seems to be the trend (Sartzetakis, 2019).

The non-recourse project financing scheme will be the one examined in this dissertation, since government subsidies are no longer offered for RES projects, while the issuing of bonds fall under a balance-sheet debt structure, that could be part of another assessment.

The valuation of the investment is performed based on the Discounted Cash Flow Principle. The net present value (NPV) and Internal Rate of Return (IRR) shall be used, which are classical tools used when performing valuation of investment projects (Monjas-Barroso & Balibrea-Iniesta, 2013).

2.2. Non- recourse Project financing

The non-recourse project financing method differs from the usual method of corporate financing (balance - sheet financing), since it is the revenues of the project that will repay the loan, and the lender does not hold any other collateral or debt security (Firouzi & Meshkani, 2021). It is common for a Sponsor to create a commercially self-contained SPV to separate other Sponsor's assets and use it as the company that will realize the project (Steffen, 2018). Gatti (Gatti, 2013) defines project finance as "the structured financing of a specific economic entity – the SPV – created by sponsors using equity and for which the lender considers cash flows as being the primary source of loan reimbursement, whereas assets represent only collateral".

In fact, first appearance of such structure for the development of energy resources was back in the 1930's in the Southwestern United States (Pollio, 1998), a typical example of capital-intensive investments by Sponsors with insufficient creditworthiness or unwilling to assume all investment risks (Aralica, Račić, & Šišinački, 2007). Project finance is considered important for Renewable Energy Projects and Steffen (Steffen, 2018) discusses eight reasons why to use project finance, in order to prevent negative financial synergies with existing business, address market imperfections and to obtain advantageous organizational structure. Furthermore he discovers that 88% of Onshore Wind projects and 96% of PV projects use project finance.

It is therefore easily derived that RES investments in Greece also rely heavily in bank loans in terms of non-recourse financing, since they are highly flexible in tenors and types (Shan, Hwang, & Zhu, 2017). They also offer high debt to equity ratios – commonly 75/25, in par with similar international investments (Osei-Kyei & Chan, 2018), as well as long repayment periods reaching 15-20 years, depending on the expected cash-flows (Qian, et al., 2019).

The main evaluation tool of the bankability of a project is the Debt Service Coverage Ratio (DSCR), which examines the ability of the cashflows to repay that year's debt service, while the Loan Life Coverage Ratio (LLCR) examines this ability for the lifetime of the loan (Borgonovo & Gatti, 2013). These metrics are considered crucial for the evaluation of the loan by the lender and are calculated from the project's financial model (Ravis, 2013). The threshold for these ratios is usually set at 1,30x, while in case lower values are identified during the life of the project, actions are taken such as no dividend payments, curing or step-ins and novations (The World Bank, 2020).

2.3. Valuation approaches

In order to evaluate a renewable energy investment, calculating expected revenues and expenditures and discounting the net cash flows with a previously determined rate of return, is the most popular method (Shimbar & Ebrahimi, 2019). This Discounted Cash Flow valuation, compared to other valuation approaches discussed by Damodaran (Damodaran, 2012) such as Relative Valuation or Contingent Claim Valuation seems to be more representative for the investment assessed and the procedure followed.

There are some drawdowns to this approach however, as pointed out by Siddiqui, Marnay & Wiser (Siddiqui, Marnay, & Wiser, 2005), since it considers that there is a significant amount of certainty to the cashflows, which is not always the case. These could be handled by evaluating potential risks and following relevant strategies, as described in Espinoza & Rojo's (Espinoza & Rojo, 2014) Decoupled NPV (DNPV) method. This analysis uses modern financial techniques, such as option pricing, to cost these risks and include them in the valuation. A similar approach by Shimbar & Ebrahimi (Shimbar & Ebrahimi, 2019) showed that a project with a negative NPV could show a positive DNPV, while a real options approach was also followed by Abadie & Chamorro (Abadie & Chamorro, 2014) to valuate Wind energy Projects under various incentive schemes and assessed optimal investment timing.

Menegaki (Menegaki, 2007) summarized valuation methods, such as Stated and revealed preference valuation methods, option theory and portfolio analysis. She also considered Emergy analysis as an alternative to market valuation but by no means a substitute.

Although Venetsanos et al (Venetsanos, Angelopoulou, & Tsoutsos, 2002) consider that the "Traditional discounted cash flow (DCF) approaches can neither properly deal with unexpected market developments nor allow for management's flexibility to adapt and revise later decisions in response to them", Frayer & Uludere (Frayer & Uludere, 2001) discover that significant mathematical complexities are brought out when trying to price an option, which uncovers the methodology's shortfalls.

Conclusively, in this dissertation the DCF valuation method is followed, due to the complexity and difficulties to be expected if more complex methods were to be followed.

3. Renewable Energy Sources Legislative Framework

3.1. Introduction

The Private energy investments in Greece were initiated after the issuance of law 2773/1999 which established the transformation of the energy market from wholly state owned to both state owned and private sector owned. Investments in the renewable energy sector were introduced with law 3468/2006 and revised with several acts, the main of which are law 3734/2009, 3851/2010, 4001/2011 and 4524/2014.

In view of the target model to come following EU's third energy package, law 4414/2016 was introduced, which altered the supporting scheme form a fixed tariff (Feed-in-Tariff) incentive to a market up share incentive in the form of a Feed-in-Premium. Law 4512/2018 defined the new electric energy markets and finally law 4685/2020 was passed, with the aim to simplify the RES licensing process and restructure the environmental legislation.

Several Ministerial Decrees were also issued in order to define procedures, issues and details regarding the energy market.

3.2. Licensing procedures

The main permits to be issued follow a serial flow as follows:

Producer's Certificate (former Production License) – Environmental Terms Approval – Installation license – Building permit (or small scale works permit) – Construction – Operation License.

A significant factor regarding investments in the energy sector, is the connection of the investment to the electricity grid. This is performed (according to the installed capacity of the station) either at the low voltage or the medium voltage distribution grid, or at the high voltage or the ultra-high voltage transmission network. The method of connection to the grid is defined by the respective network operator. This method, referred to as grid connection terms is announced to the investor and upon acceptance and issuance of the project's ETA they are considered binding and are documented in a grid connection agreement.

The incentive scheme to be followed either as a fixed tariff incentive or as a sliding premium incentive is documented in a power purchase agreement or a sliding premium (of fixed price) aid agreement.

Above mentioned permits and contracts shall be analyzed in the following paragraphs.

3.3. Main permits

3.3.1. Producer's Certificate

The initial license to be obtained concerning a Renewable Energy project is the Producer's Certificate (which after law 4685/2020 replaced the Production License), issued by the Regulatory Authority of Energy. The certificate is issued after an electronic application within one of the three licensing rounds performed each year, for projects that comply with the following factors:

- They do not pose a threat to national security
- They do not pose a threat to health and safety issues
- The project's location does not contradict spatial planning restrictions
- The electricity grid at the project's area is not saturated
- The affected municipality's carrying capacity is not saturated.

For special projects such as hybrid, geothermal, offshore wind and clusters of wind farms above 150MW, additional criteria such as business plan, project IRR, applicant's financial standing etc. are also examined.

The Producer's Certificate is issued within 45 days from the approval of the application, with a validity of 25 years which can be extended for a further period of 25 years.

Once the certificate is issued, the investor must proceed with the application for an ETA, within six months, extendable to 12 months for projects that require a special ecological assessment. He must also arrange to apply for the binding grid connection terms within thirty six months.

The deadlines defined in the law may be extended by up to twenty four months with a payment of a retainer fee.

3.3.2. Environmental Terms Approval

The environmental approval defines the terms and conditions under which the project shall be constructed, operated and decommissioned. The approval is based on the examination by the competent authority of an Environmental Impact Assessment study which examines interaction of the project with its environment.

The projects are divided according to their environmental impacts within two categories, as per law 4014/2011, Category A where significant impacts may be inflicted to the environment and Category B with non-significant impacts. Category A is further subdivided to A2 and A1 when important and very important impacts are respectively expected.

Ministerial decision ΥΠΕΝ/ΔΙΠΑ/74463/4562/6-8-2020 defined the criteria for the classification of the projects as per the following table.

Project Type	**Subcategory A1**	**Subcategory A2**	**Subcategory B**	**Remarks**
Wind Farms	P>60 MW or P>45MW within Natura 2000 or L≥20km	10<P≤60MW and L<20km	0,02<P≤10MW or P≤0,02 *	* the project is located within a Natura 2000 region or at a distance of less than 100m from the shoreline.
PV plants		P > 10MW	1<P≤10MW or P<=1 *	
Solar thermal	P>50 MW	10<P≤50MW	1<P≤10MW or P<=1 *	
Geothermal	P>50 MW	0,5<P≤50MW		
Bioliquid	P>10 MW	P≤10MW		
Biogas or Gasification	P>10 MW	P≤10MW		
Biogas from non-hazardous waste (R3)	According to Annex IV, group 4, a/a 11			
Biogas from energy crops and ensilage	Q>150.000t/year	Q≤150.000t/year		
Biomass	P>10 MW	P≤10MW		
Hydro	P>15 MW or V>2.000.000 m^3 or diversion of water outside catchment area or L>15 km outside Natura 2000 or L>8km within Natura 2000	P≤15MW and V≤2.000.000 m^3 and 15km≥L>250m outside Natura 2000 and L≤8km within Natura 2000 and diversion of water within same catchment area	All other cases except ≤0,5MW installed in water supply or irrigation networks or sewerage,	

Table 3-1

Category B projects can subject themselves to Standard Environmental Commitments (SEC) and avoid the performance of an EIA. The respective approval is issued by the service issuing the operating license.

Regarding Category A2 projects, these are examined by the Decentralized Regional Authority, while Category A1 projects are assessed directly by the ministry of Environment. The competent authority requests opinions from public authorities such as the Forest Authority, the Ministry of Defense, the Civil Aviation Authority, the Ephorates of Antiquities (Prehistoric & Classical, Byzantine, Contemporary), the local Urban Planning

Authority, the Tourism Organization, the Transportation ministry, the local municipal and regional councils etc. which must provide acceptance or objections or terms within a pre-defined period.

The ETA is valid for a period of 15 years and may be renewed when close to expiration, while the approval of a project's SEC is indefinite and does not need a renewal.

3.3.3. Installation license

The respective license is issued after a project has secured its ETA as well as Binding Grid connection terms (to be analyzed in a forthcoming paragraph), has secured rights over the land to be used and has awarded the implementation studies to competent engineers.

The securing of private lands must be performed by respective purchase or lease contracts, while in the cases of municipal, agricultural or other publicly owned land, the investor must participate in a tender to secure lease rights. In the case of public forestry land, an intervention permit must be approved by the forestry authority and be included in the ETA, while the investor must pay a land use consideration and proceed with the reforestation of an area of equal size with the intervention land, in an area to be appointed by the forestry department. Installation of the investor to the forestry land takes place with the signing of an installation protocol by the forestry department.

3.3.4. Building permit

A building permit or a small scale works permit, issued by the respective urban planning authority is required, in order to allow commencement of works for the realization of the project and its accompanying works. The latter may include access roads, cable routing, HV substation construction, water intake works or others.

3.3.5. Operation License

Following completion of project construction and performance of a trial run within which conformity of produced energy characteristics with grid regulation is confirmed, an operation license is granted. This is issued by the decentralized authority and signifies the end of development and construction period and the start of the commercial operation of the investment. The Operation License has a validity of 20 years (25 for solar thermal) and may be extended for a further period of 20 years as long as all other permits are valid and a Power Purchase agreement is in place.

3.4. Grid connection

The connection of a RES project with the electricity network may be materialized under conditions issued by the grid operator, that is the distribution grid operator (HEDNO) for projects up to 8MW and the transmission grid network (IPTO) for projects above 8MW. The operator performs a study to identify the point and method of connection which will allow full injection of the produced power, while at the same time the grid stability will not be endangered.

The connection method referred to as grid connection terms defines the point of connection as well as the grid or network upgrade or extension works required, in order to allow such connection. These may include replacement of a part of the MV grid with upgraded conductors, construction of a new MV overhead or underground route to a point of connection or a substation, extension of a substation by installing an IPPM or a new transformer or even constructing a new HV or UHV substation and connecting it to the transmission system through a new HV or UHV network. In several cases, common grid connection terms with other projects are issued, in order to optimize costs for the investors. These provisional grid connection terms once issued, must be accepted by the investor and be used as reference in the environmental licensing of the project as accompanying works.

The issuing of the ETA allows the investor to request from the grid operator to establish these terms as binding and proceed with the signing of a grid connection contract within which the performance of the grid connection works will be defined. For the period up to the signing of the contract, the investor provides a letter of credit to the operator, to secure the terms. Actual construction works may be implemented either directly by the grid operator or by the investor under the supervision and acceptance of the grid operator.

3.5. Incentive Framework

3.5.1. Feed in Tariff

The incentive scheme of compensating the energy injected by a RES producer to the electricity network with a fixed price per volume of energy (Feed in Tariff), was introduced with law 3468/2006. This scheme predefined the prices at which Wind Farms, Photovoltaic stations, Hydroelectric stations, other Solar, Geothermal, Biomas, Biogas, High Efficiency Cogeneration or other RES stations would be paid for the produced energy, both in the interconnected system and in the non-interconnected islands. All produced energy would be paid for in the interconnected system, while RES stations had dispatch priority over the remaining electricity producers. The prices were quite attractive, especially for PV stations where the FiT was set at 450€/MWh for stations up to 100kWp. It should be noted that the retail electricity price at the time was in the vicinity of 100€/MWh.

The initially announced tariffs were reduced with laws 3734/2009 and 3851/2010 and several ministerial decisions, however all changes took effect after a period of time and only to newly connected stations. Law 4524/2014 however also known as the “new deal” counteractively reduced all tariffs and clawed back a percentage of previous year’s earnings from all RES producers.

In the non-interconnected islands, there would be some cases where not all produced power was absorbed – and therefore compensated – due to grid stability reasons. For this reason, the tariffs in the islands were higher than the ones of the mainland by 10-15%.

The RES producers, apart from their requirement to abide with the grid code regarding quality of produced energy, did not have any other obligations applicable to other electricity producers such as participation in the energy market, nor did they have any forecasting or balancing responsibilities. The compensation did not come from the electricity market, rather than a Special Account for RES (ΕΛΑΠΕ in Greek), mainly funded by the Special Duty of Greenhouse Gas Emissions Reduction.

Their monthly compensation was easily calculated by the formula:

$$R=Q_m*FiT$$

Formula 3-1

Where R is the remuneration

Q_m is the produced energy within the month and

FiT is the technology’s predefined tariff.

3.5.2. Feed in Premium

The incentive scheme was modified in 2016 with law 4414/2016, which set the framework of remunerating the RES producers through the electricity market and then adjusting the difference to a pre-defined Reference Price. Similar schemes were also followed in other European countries and were called Contracts for Difference (CfD).

In this scheme, RES producers participate in the Day Ahead Market and get remunerated at the System Marginal Price for each hour of production. Through their market participation, stations undertake the obligations of all other producers, such as declaring the energy they will inject each hour segment of the following day and undertake the responsibility to balance any deviations from this estimation. Due to the nature of most RES, where the hourly production depends on either sunshine or wind speed, forecasting is not a straightforward process and often leads to variations, it is therefore commonly outsourced to Aggregators through which stations participate in the market and to which this responsibility is transferred.

The stations enter into a Sliding Premium Aid Agreement with the Administrator of Renewable Energy Sources and Guarantees of Origin (ARESGO) and are remunerated each month with the difference between the technology specific Special Market Price and their secured Reference Price. The latter is either administratively defined for some producers (e.g. those who entered into a SPAA before the end of 2016 or small stations) or obtained through the participation in a tender process periodically held by RAE. Smaller stations are remunerated through a Fixed Price Aid Agreement, with similar terms as the old FiT scheme.

The total remuneration the stations enjoy is the sum of the market remuneration and the sliding premium remuneration (R_{market}+$R_{sl,prem}$), which are calculated as follows:

$$R_{market} = \sum_{h=1}^{n} Q_h * SMP_h$$

Formula 3-2

Where h is each hour in the month and n all hours of the month, Q_h the produced energy at hour h and SMP_h the System Marginal Price at hour h.

$$R_{sl.prem} = (RP_{station} - ETA_{tech}) * (Q_{station} - Q_{station\text{-}SMP=0>2})$$

Formula 3-3

Where $RP_{station}$ is the station's secured Reference Price, ETA_{tech} is the Special Market Price for the station's technology, $Q_{station}$ is station's produced energy during the month and $Q_{station\text{-}SMP=0>2}$ is the amount of energy produced when SMP was zero for more than 2 consecutive hours.

The ETA is calculated according to the provisions of M.D. ΑΠΕΗΛ/Α/Φ1/οικ.187480 ΦΕΚ 3955Β' 9/12/2016 (as amended), as follows:

$$ETA_{tech} = \frac{\sum_{h=1}^{n} SMP_h * Qtech_h}{\sum_{h=1}^{n} Qtech_h}$$

Formula 3-4

ETA_{tech} is the technology specific Special Market Price, for PV, wind or other RES, h is each hour in the month and n all hours of the month,

SMP_h is the System Marginal Price at hour h and

Q_{tech} is the energy produced by all producers of the same technology (pv, wind etc) at hour h.

Although the producers are not directly compensated with the reference price, since the ETA is calculated averaged per technology and not per station, the differences are minor and the monthly remuneration may therefore be modeled as

$$R = Q_m * RP_{station}$$

Formula 3-5

Where R is the remuneration

Q_m is the produced energy within the month and

$RP_{station}$ is the station's secured Reference Price.

A simplified graphical representation of the mechanism is shown below.

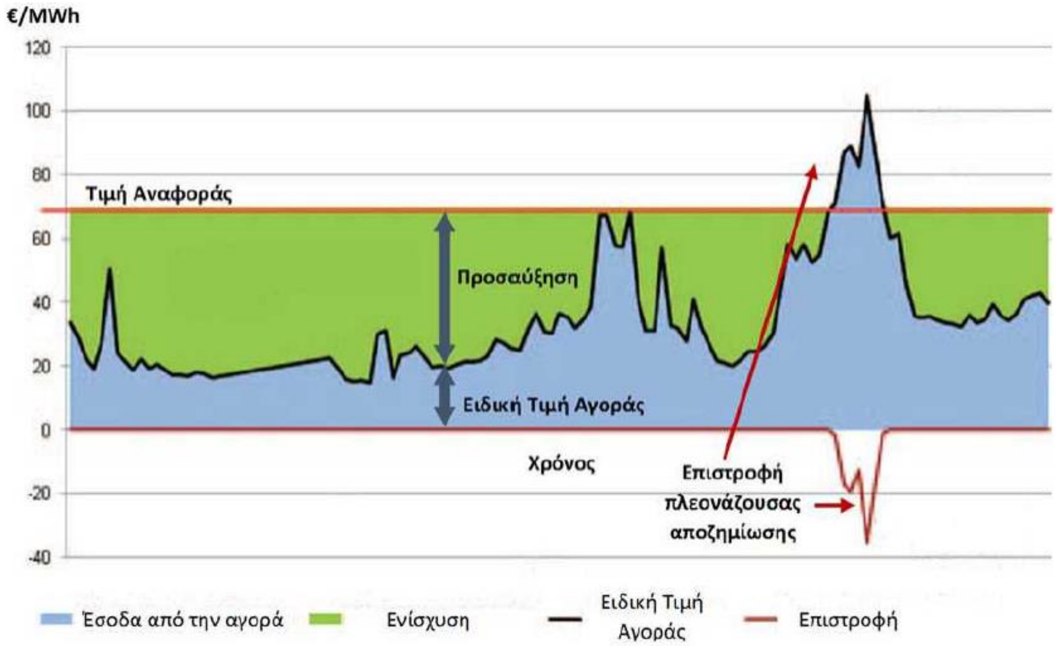


Figure 3-1 (Regulatory Authority of Energy, 2020)

The Feed in Premium incentive scheme is considered a provisional phase to promote development of RES, in order to reach the national and European Energy and GHG reduction goals, while in the future state subsidies are expected to be withdrawn.

3.6. The Target Model

The Target Model is an integration of all European energy markets, with the purpose of increasing the competition by reducing the market concentration, while efficiency, liquidity and transparency are expected to be promoted (ENTSO-E, n.d.).

In Greece, four markets were created, namely:

The **Energy financial market** (Derivatives market), where electricity sale and purchase contracts are traded. These contracts refer to optional physical delivery obligation and financial products such as options and futures can be traded within it (Energy Exchange Group, n.d.).

The **Day-Ahead Spot** market is the main market in which electricity is traded. It refers to quantities of energy to be produced, delivered and consumed the following calendar day. Bids are defined on the previous day (D-1) and physical delivery takes place on day D. The market operates on auctions cleared by the Euphemia Pan-European algorithm which is based on three principles, "a single algorithm, robust operation and individual power exchange accountability" (Energy Exchange Group, n.d.). The agreed price for every hour is defined based on the volume of demand and supply. RES producers bid only for the offered quantity, with a zero price.

Within the **Intra-day market** participants trade energy for the day of fulfillment of the physical delivery. This market operates supplementary to the Day Ahead market after its declaration deadline. Its aim is to allow minimization of imbalances of net positions in real-time (Independent Power Transmission Operator, n.d.).

The **Balancing market**, operated by the Independent Power Transmission Operator, unlike the other markets operated by the Hellenic Energy Exchange, consists of three processes:

- ✓ The balancing capacity market
- ✓ The balancing energy market
- ✓ Imbalances settlement

The market "includes all necessary procedures for the continuous adjustment of the total production to the total load with the purpose of maintaining a "stable" frequency at the System" (Independent Power Transmission Operator, n.d.).

Renewable Energy Sources producers may participate in the above mentioned markets without being necessarily subsidized through aid agreements. Their participation may either be performed in person with direct registration in HEnEX, or through an aggregator or the Last Resort Aggregator.

Additionally, participation in the market is also possible through bilateral contracts directly with an offtaker, under mutually agreed terms and period. The latter may allow for a long term income calculation of the producer, with the risk residing in the credibility of the offtaker.

4. Onshore Wind farm case study

4.1. Introduction

This case study assesses the financing possibilities and valuation parameters of a contemporary onshore wind farm, to be constructed within current incentive schemes as well as within the aid-free options of the Target Model.

The case to be examined shall be of a wind farm installed in the Greek mainland with parameters as close as possible to the typical ones. Wind Turbine Generators in the magnitude of 3-4 MW each shall be utilized, with a blade span of 130-150m. These types can be installed in areas with a medium to good wind potential and could experience a Capacity Factor (CF) in the vicinity of 30%, even more in the near future. A CF of 25% used to be the market average for such investments, however the decrease of incentives along with the technology optimization allowing for utilization of fields with a less-that-optimal wind potential, is currently readjusting the norm. It should be noted that CF are calculated with exceedance probability scenarios (commonly P50-P75-P90), based on the various measurement, equipment and other uncertainties. Further analysis is not part of this document, therefore whenever a CF is used, it is considered as the one with exceedance probabilities acceptable to the entity examining the investment.

The size of the wind farm will be in the vicinity of 40MW with 10 WTG, to allow for better allocation of the fixed costs of access route and grid connection.

Grid connection is considered with a new 33/150kV substation within a distance of 10km from the WF's control building, situated under an existing 150kV line, in order to avoid HV line routing.

4.2. Onshore Wind Farm with FiP

The inputs to be considered in the financial model for a wind farm with a FiP incentive scheme are divided in four categories, namely

- ✓ Capital expenses – CAPEX
- ✓ Income
- ✓ Operational expenses – OPEX
- ✓ Financial parameters

As analyzed in the respective paragraphs.

4.2.1. Incentive framework

The incentive framework assessed is this case is the Sliding Premium (FiP) above the market spot price, which assures that the investment is remunerated with a more-or-less fixed price (the Reference Price), as described in chapter 3.5.2. This allows us to model the expected cash inflow with significant accuracy, with the only variable being the actual wind yield.

4.2.2. Income

The income to be considered in the financial model is calculated as the product of estimated electricity production by the FiP price.

As explained earlier, current WTG achieve a CF of 30% in average fields (including all losses and availability), therefore the produced energy for a 40MW wind farm shall be: 40MW*365days*24hours*30%=105.120MWh.

The remuneration price, as per RAE's July 2020 tender was 55,67 €/MWh on average (Regulatory Authority of Energy, 2020), therefore this is what we shall consider.

Conclusively, annual average income of the wind farm shall be 5.852.030,40€. This sum is considered fixed for the whole lifetime of the project.

4.2.3. Capital Expenses

The Capital expenses to be considered refer to the investment cost and include all necessary expenditures to develop, construct and commission a fully operational Wind Farm with the characteristics described above.

The CAPEX cost per installed capacity is estimated as 1,10€/W, as per current market and is divided for a 40MW wind farm as follows.

Cost category	Cost
Development - studies	1.000.000 €
WTG	30.400.000 €
S/S	3.500.000 €
MV grid - external	1.200.000 €
MV grid - internal	360.000 €
Control building	200.000 €
Roads and platforms	2.000.000 €
WTG foundations	2.500.000 €
Construction Supervision	500.000 €
Land and other costs	215.000 €
Financing costs - arrangement fee	330.000 €
IDC	1.221.000 €
Contingencies 5%	574.000 €
TOTAL	**44.000.000 €**

Table 4-1

The cost for the development, full permitting and performance of the implementation studies is considered at 1.000.000€, which is within current market standards.
The cost of the Wind Turbines supply, erection and commissioning is estimated at 750.000€/MW, which is currently the prevailing market price.
The cost for the HV substation is once again considered at the average market price, with the assumption that no HV line will be built and a 40/50MVA transformer will be installed. It should be mentioned that quite frequently other RES projects acquire grid connection terms for the same substation and participate in these common connection works, however in this case no cost sharing is assumed.
The cost of the external MV grid, from the Wind Farm's control building to the S/S is estimated at 40.000€/km for the routing earthworks, as well as 40.000€/km for each MV circuit with a capacity of 20MW. Conclusively, the cost for the 10km of the network is expected to reach 1.200.000€.
For 10 wind turbines with a blade span of 150m their minimum distance will be 2.5D= 2.5*150=375m. Therefore the total length of the wind farm will be at least 3.75km. Due to the topography in the Greek mountains, being able to fit 10 WTG in 3.75km is not very easy, therefore assuming a total distance of 4.5km seems more realistic. The control building shall be installed at a position to optimize the internal and external grid connections, therefore considering a cost for the internal grid of 4.5*80.000€=360.000€ seems realistic.
The control building is estimated at 200.000€, as per current market prices, while roads and platforms are expected to cost roughly 200.000€ per WTG location, that is 2.000.000€ for the whole farm. A short access road as well as possible interventions to the access roads are considered within this sum, while with the assumption that blades will be transported with a blade lifter allows us to consider such interventions limited.
Currently, WTG foundations are constructed with approx. 250.000€ each, therefore a total sum of 2.500.000€ is considered. Additionally a sum of 500.000€ is considered for construction supervision and quality control on behalf of the investor, as well as 215.000€ for land and other costs. It should be noted that wind farms are commonly constructed in public forestry land and pay a once-off consideration for the land and reforest an equal area. A sum of 574.000€ is also considered as 5% contingencies on all expenses except WTG cost.

Additionally, a Financing costs and arrangement fee of 330.000€ is considered, as well as capitalized interest during construction (considering one year construction period) at 1.221.000€.

VAT is not used or calculated in the CAPEX cost, as it is considered fully refundable, while for the WTG not payable at all, and any interest of a possible tranche that would finance it could be safely paid by the contingency amount.

4.2.4. Operational Expenses

The Operational expenses to be considered in the financial model are approx. 17% of income for the first year and are divided as follows.

Cost category	Cost (€)
WTG O&M fee	500.000,00
BOP maintenance	50.000,00
S/S maintenance	30.000,00
Insurance	93.454,06
Aggregator fee	157.680,00
ARESGO fee	34.164,00
Electricity consumption	17.556,09
Personnel cost	50.000,00
Admnistrative expenses	50.000,00
Contingencies	17.145,85
TOTAL	**1.000.000,00**

Table 4-2

The O&M cost of the WTG is estimated according to the following table.

Years	Fee per WTG (€)	Total fee (€)
1-5	50.000,00	500.000,00
6-10	60.000,00	600.000,00
10-15	65.000,00	650.000,00
16-20	75.000,00	750.000,00

Table 4-3

Conclusively, the annual fee is inserted in the model incrementally as per the above table.

The cost for the annual BOP maintenance is estimated at 50.000€ in an annual basis, which includes control building and grid lines' preventive maintenance, as well as local repairs in the road network. The substation preventive maintenance cost is estimated at 30.000€ per year, as per market practice.

The insurance cost for machinery breakdown and loss of profit is estimated at 0,2% of the insured capital, that is the construction cost (CAPEX cost minus development and financial costs) as well as the annual income.

The aggregator fee is expected to be 1,5€/MWh, therefore 157.680,00€ for the expected yield of 105.120MWh, while the fee of ARESGO was set for 2021 at 0,325€/MWh resulting in a total fee of 34.164,00€.

The cost of consumed electricity at hours of non-production is estimated at 0,3% of income, while personnel cost and administrative expenses at 50.000€ each, on an annual basis. An additional contingency amount of 17.145,85€ is considered, summing up the total OPEX costs for the first year at 1.000.000,00€.

It should also be mentioned that a levy of 3% is payable from all RES producers (except PVs unless participating in a technology neutral RAE tender) to the local municipality. This cost is not included in the OPEX sum but considered separately in the financial model.

4.2.5. Financial Parameters

In this case study where the amount of income is considered more or less secured, Lenders commonly participate in project financing on an non-recourse basis, undertaking up to 75-80% of the investment cost, as long as the Debt Service Coverage Ratio (DSCR) is kept above 1,3-1,4 during the tenor of the loan.

In the case examined, a LTC ratio of 75% is selected, while DSCR is checked for various tenor periods, up to 20 years.

The loan interest considered is 3,7% while the repayment method shall be annual interest payment as well as equal capital repayments.

An arrangement fee including various financing costs at 1% of the loan is considered, as well as capitalized interest during the construction period, which in this case is considered one year. Lenders also commonly finance DSRA, OPEXRA and MRA accounts, but in this case their costs are considered included in the estimated interest.

A CPI of 1% is also considered, regarding the indexation of OPEX costs.

The cost of equity is considered 9%, resulting in a WACC of 25%*0,09+75%*0,037*(1-24%)=4,36%. Regarding tax, an income tax of 24% is considered, as well as a straight line depreciation period of 20 years.

4.2.6. Financial model

The financial model was prepared in an excel sheet for the 20 years of the expected FiP contract duration.

For the first year, the following calculation method was followed.

Income was calculated as per par. 4.2.2, while operational expenses and levies as per par. 4.2.4. It should be noted that in years 6, 11 and 16 additional WTG O&M costs kick in and are respectively modelled. The EBITDA was calculated by subtracting OPEX and levies from the income. The Capital debt at the beginning of the financial model equals the project's financed CAPEX (75%) as per par. 4.2.3, while the capital repayment sum was capital debt divided by the loan tenor (i.e. 20 years). The accrued interest was calculated upon the outstanding debt, while the debt service is the sum of capital repayment and accrued interest. The depreciation was the quotient of CAPEX divided by the depreciation period of 20 years, while EBT was calculated by subtracting from EBITDA the interest paid and the depreciation. Income tax was calculated by multiplying the tax rate with EBT, while CFADS was calculated by subtracting income tax from EBITDA. The net result was calculated as the difference of EBT and income tax, while for the FCFE calculation, Debt service and tax are deducted from EBITDA. The results of the first year are tabulated below, while for the 20-year operating period in the following table, where sums are rounded in k€ in order to fit the page.

Year	**1**
Income	5.852.030€
OPEX	1.000.000€
levies	175.561€
EBITDA	4.676.469€
Capital debt	33.000.000€
Capital repayment	1.650.000€
Interest	1.221.000€
Debt service	2.871.000€
Depreciation	2.200.000€
EBT	1.255.469€
Income tax	301.313€
CFADS	4.375.157€
Net result	954.157 €
FCFE	1.504.157 €

Table 4-4

	Wind Farm with FiP financial model																			
	Sums in .000€																			
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Income	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852	5.852
OPEX	1.000	1.010	1.020	1.030	1.041	1.152	1.164	1.175	1.187	1.199	1.261	1.274	1.287	1.299	1.312	1.427	1.441	1.455	1.470	1.485
levies	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176
EBITDA	4.676	4.666	4.656	4.646	4.636	4.524	4.513	4.501	4.490	4.478	4.415	4.403	4.390	4.377	4.364	4.250	4.236	4.221	4.207	4.192
Capital debt	33.000	31.350	29.700	28.050	26.400	24.750	23.100	21.450	19.800	18.150	16.500	14.850	13.200	11.550	9.900	8.250	6.600	4.950	3.300	1.650
Capital repayment	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650	1.650
Interest	1.221	1.160	1.099	1.038	977	916	855	794	733	672	611	549	488	427	366	305	244	183	122	61
Debt service	2.871	2.810	2.749	2.688	2.627	2.566	2.505	2.444	2.383	2.322	2.261	2.199	2.138	2.077	2.016	1.955	1.894	1.833	1.772	1.711
Depreciation	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200	2.200
EBT	1.255	1.307	1.357	1.408	1.459	1.409	1.458	1.508	1.557	1.606	1.605	1.653	1.701	1.750	1.798	1.745	1.791	1.838	1.885	1.931
Income tax	301	314	326	338	350	338	350	362	374	385	385	397	408	420	431	419	430	441	452	463
CFADS	4.375	4.353	4.331	4.308	4.286	4.186	4.163	4.139	4.116	4.092	4.030	4.006	3.981	3.957	3.933	3.831	3.806	3.780	3.754	3.729
Net result	954	993	1.032	1.070	1.109	1.071	1.108	1.146	1.183	1.221	1.220	1.256	1.293	1.330	1.366	1.326	1.361	1.397	1.432	1.467
FCFE	1.504	1.543	1.582	1.620	1.659	1.621	1.658	1.696	1.733	1.771	1.770	1.806	1.843	1.880	1.916	1.876	1.911	1.947	1.982	2.017

Table 4-5

The following modelling indicators were calculated:

LCOE@WACC	51,75€
LCOE@10%	69,64€
LCOE@7,5%	61,32€
NPV equity	4.486.701,88€
NPV project	10.087.928,46 €
equity IRR	14,05%
project IRR	6,94%

Table 4-6

From the calculated indicators we derive the following:

LCOE of the project of 51,75€/MWh is close to the FiP used of 55,67 €/MWh, indicating a balanced financial model, but slightly under remunerated. It should be noted that LCOE is also calculated with a 10% discount rate or a 7,5% discount rate, in order to be comparable with international investments.

Positive NPV for equity and overall project are calculated, since equity and project IRRs are both above the estimated cost of equity and WACC respectively. The high equity IRR compared to the cost of equity is mainly due to the high equity gearing ratio.

4.2.7. Financing

The financing of the investment could either be performed by full equity, by issuing a corporate bond loan, or by project finance in a non-recourse basis.

The latter form of financing the investment is the most commonly encountered in Greece, due to current low interest rates, high tax rates and a favorably high gearing ratio which leads to very low WACC. As seen above, the calculated WACC for the investment reached 4,36%, while IRENA considers a WACC of 7,5% in the OECD countries (IRENA, 2020).

The metric mostly examined by financial institutions is the Debt Service Coverage Ratio (DSCR), which is the Cash flow Available for Debt Service (CFADS) divided by the Debt Service (Capital repayment plus interest) for each examined period (commonly year).

Another ratio examined is the Loan Life Coverage Ratio (LLCR), which is the NPV of all future free cashflow available for debt service at any given time, divided by the debt balance at that time.

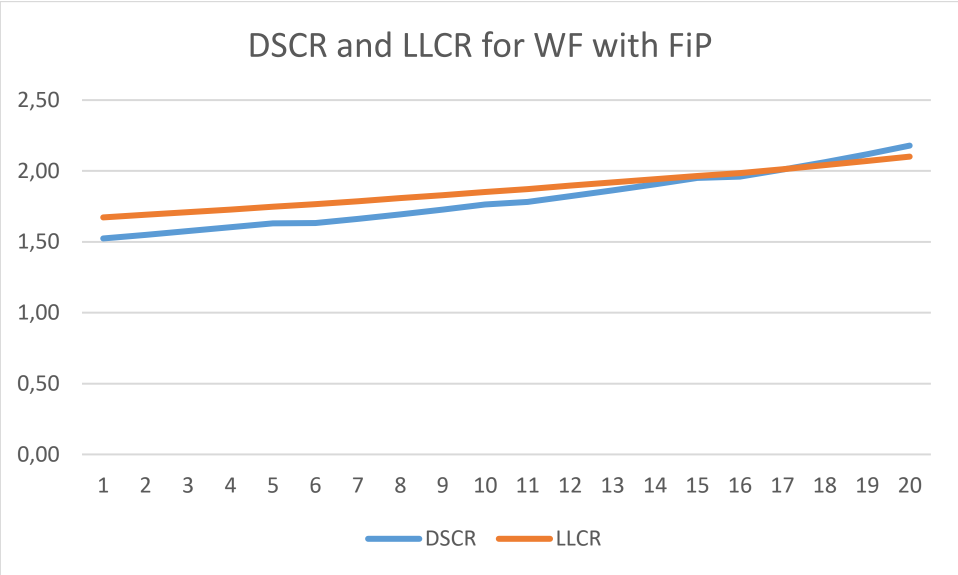
Most commonly targeted DSCR ratio is 1,3x (at P90) and 1,2x (at P99) as per Pacudan (Pacudan, 2016). For Greek banks the relevant ratio is 1.3x at P75. The same ratio shall be set as a target for the LLCR.

From the financial model examined, the relevant ratios were calculated as follows:

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DSCR	1,52	1,55	1,58	1,60	1,63	1,63	1,66	1,69	1,73	1,76	1,78	1,82	1,86	1,90	1,95	1,96	2,01	2,06	2,12	2,18
LLCR	1,67	1,69	1,71	1,73	1,75	1,77	1,79	1,81	1,83	1,85	1,87	1,90	1,92	1,94	1,96	1,98	2,01	2,04	2,07	2,10

Table 4-7

And were inserted in a diagram to indicate their trend in time.



Graph 4-1

Their positive trend in time as well as their significant distance from the 1.3x threshold, as well as the certainty of the expected income due to the secured FiP justifies the high gearing ratio and the long loan maturity periods offered.

By examining the possibility of shorter loan maturity periods, the 1.3x threshold is met at approx. 15 years. Nevertheless, due to the upward trend of the ratios, minor debt sculpturing would allow ever shorter tenors.

4.2.8. Valuation

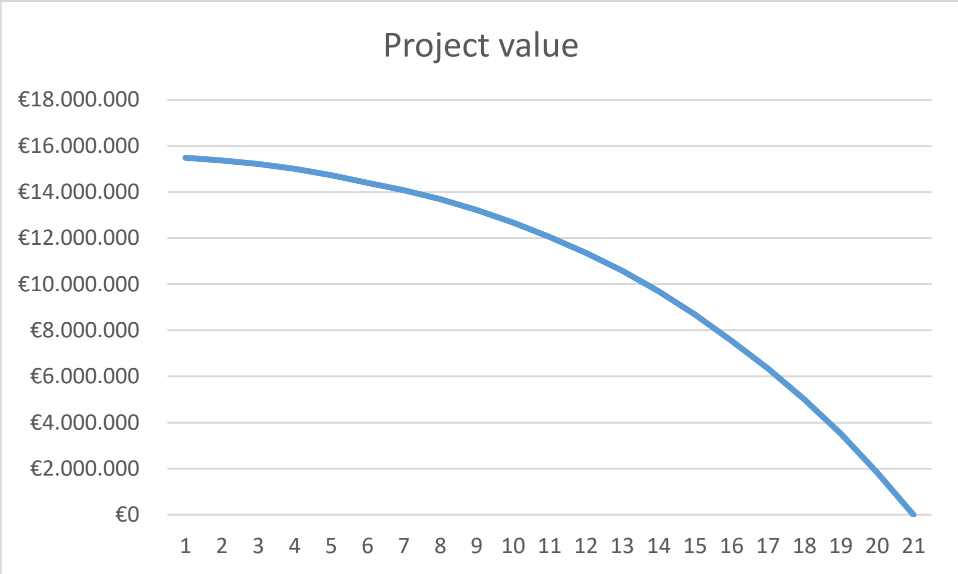
In order to valuate the investment and assess the fair price at which it could be acquired by a potential investor at any given period of time, a discounted cash flow appraisal shall be used. This method "is also considered an invaluable tool for a detailed appraisal of the potential returns from a site under several assumptions" (RICS, 2018).

The FCFE for each year is calculated, and then discounted using the equity return rate of 9% for each year forward from the year examined. Thus the NPV of all forward FCFE are calculated. Any potential investor would evaluate the investment with his own equity return rate, nevertheless the 9% ratio used can be considered a rational approach.

The values calculated at each year, are presented below.

Year	Valuation
1	15.486.702 €
2	15.376.348 €
3	15.217.265 €
4	15.005.142 €
5	14.735.282 €
6	14.402.568 €
7	14.078.180 €
8	13.686.954 €
9	13.222.963 €
10	12.679.746 €
11	12.050.262 €
12	11.365.217 €
13	10.581.706 €
14	9.690.962 €
15	8.683.432 €
16	7.548.702 €
17	6.352.183 €
18	5.012.422 €
19	3.516.635 €
20	1.850.890 €

Table 4-8



Graph 4-2

The debt has not been factored in the above estimation, meaning that a potential investor would need of course to undertake the debt of the project at any time of acquisition.

Additionally, the project is considered to have no value at the end of its lifetime, while decommissioning costs are expected to be set-off by the salvage value of the equipment.

From the above table it is easily determined that the project has an initially high value, close to 15,5M€ and retains it in such levels up to its 4th year of operation. A continuous downwards value trend is identified in this example, which gets steeper in time.

In year one, if the investor decided to sell the project, he would gain 4.486.702€ above his invested equity of 11.000.000€, that is almost 40%. This is the reason for many companies entering the Build-and-Transfer business. It should be noted however that the development costs financed during the construction of the project have in many cases been paid some years in advance, while there have also been projects whose development reached a certain point and got abandoned. This overhead therefore also represents the potential losses the developer has suffered over the years of development of various projects.

4.3. Onshore Wind Farm within the Target model

The inputs to be considered in the financial model for a wind farm within the Target model era, that is with no incentive scheme, are once again divided in the same categories, as before and analyzed in the respective paragraphs. Year 2023 is considered the examined year, since by that time, incentive schemes are expected to be reduced, closing to an end.

4.3.1. Remuneration framework

Since no incentive framework is expected to be in place after a few years, the remuneration of the station will only be through the spot market, or with a bilateral PPA. The latter is of course expected to follow the market's trend and not deviate significantly from it. In order therefore to assess the remuneration price of the injected power, the following methodology was followed.

The coupling of European markets is expected to equalize electricity prices within it, therefore the estimated baseload electricity price for the years 2020 to 2050 were derived from Energy Brainpool's EU Energy Outlook 2050 analysis (Energy Brainpool, 2019) expected power prices. Although Figure 6 of the article displays average sales values estimation of wind power, the graph in Figure 8 was utilized, since it presented both a median of the estimated price as well as exceedance probability scenarios.

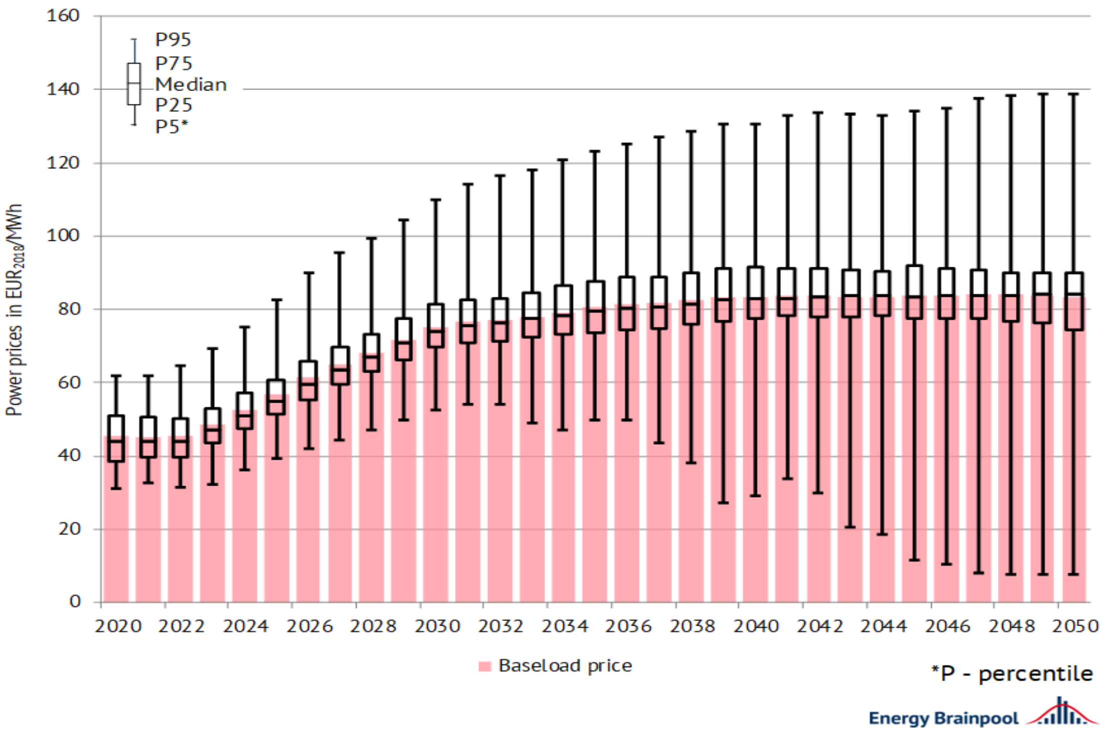
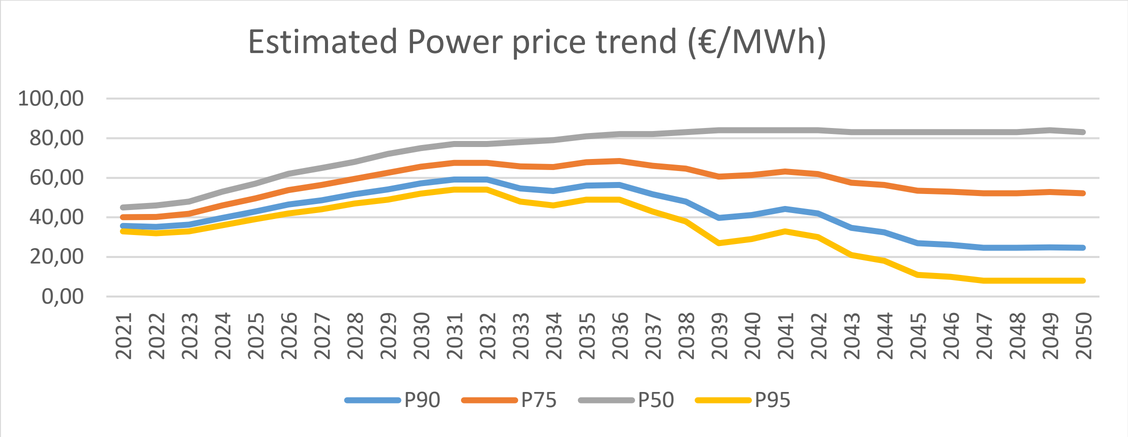


Figure 4-1. Source: (Energy Brainpool, 2019)

From the above figure, estimated average prices, as well as P5 percentile prices were graphically picked. By assuming P5 (P95) percentile at 1,645s distance from the average, standard deviation was calculated for each year and electricity prices with exceedance probabilities P75 and P90 were derived up to 2050, as follows.

	P50	**P75**	**P90**	**P95**
2021	45,00	40,08	35,66	33,00
2022	46,00	40,26	35,11	32,00
2023	48,00	41,84	36,33	33,00
2024	53,00	46,02	39,77	36,00
2025	57,00	49,61	42,99	39,00
2026	62,00	53,79	46,44	42,00
2027	65,00	56,38	48,66	44,00
2028	68,00	59,38	51,66	47,00
2029	72,00	62,56	54,10	49,00
2030	75,00	65,56	57,10	52,00
2031	77,00	67,56	59,10	54,00
2032	77,00	67,56	59,10	54,00
2033	78,00	65,69	54,66	48,00
2034	79,00	65,46	53,32	46,00
2035	81,00	67,87	56,10	49,00
2036	82,00	68,46	56,32	49,00
2037	82,00	66,00	51,65	43,00
2038	83,00	64,53	47,98	38,00
2039	84,00	60,61	39,65	27,00
2040	84,00	61,43	41,20	29,00
2041	84,00	63,07	44,32	33,00
2042	84,00	61,84	41,98	30,00
2043	83,00	57,56	34,76	21,00
2044	83,00	56,33	32,42	18,00
2045	83,00	53,46	26,98	11,00
2046	83,00	53,05	26,20	10,00
2047	83,00	52,22	24,64	8,00
2048	83,00	52,22	24,64	8,00
2049	84,00	52,81	24,86	8,00
2050	83,00	52,22	24,64	8,00

Table 4-9



Graph 4-3

The above graph depicts the price trend and the following conclusions can be derived by it. The price of baseload electricity is expected to rise significantly up to 2030, after which the curve slightly flattens. The trend depicted for P75, P90 and P95 exceedance probability scenarios are caused due to the increasing uncertainty for the future, rather than a downwards trend of the price. Nevertheless, since investors and financial institutions will experience the same uncertainty for the price trend, decision making is also expected to be performed with similar pessimistic price scenarios.

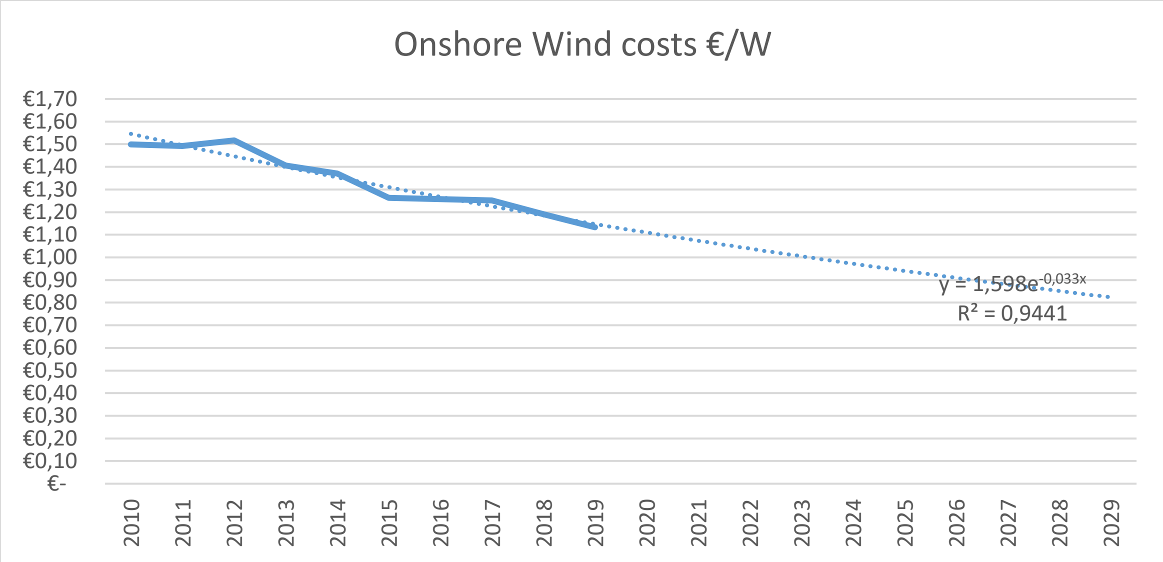
4.3.2. Income

The income to be considered in the financial model is calculated as the product of estimated electricity production by the price scenario of the previous paragraph. Initially Scenario P75 was selected, since it is the norm for financing institutions. For years 2023 to 2042, the respective scenario averaged 60,76€/MWh, which is higher than the previously examined FiP scenario. Financial institutions are therefore not expected to follow it in the near future and turn their decision making to P90 price trend scenarios, in order to be on the safe side. The P90 scenario averaged 49,12€/MWh which is considered more representative for years to come.

Same as in the previous example, the produced energy for the 40MW wind farm shall be: 40MW*365days*24hours*30%=105.120MWh.

4.3.3. Capital Expenses

The Capital expenses are expected to slightly reduce in the future, due to the development of technology. In order to assess the construction costs in the future, IRENA power generation cost (IRENA, 2020) historical trend for wind (p.29) was examined, and by assuming an exponential trendline of historical construction costs and dividing by 1,3 to include EUR/USD exchange rate and bring to current Greek prices (1,1€/W in 2020), future costs were estimated.



Graph 4-4

The trend shows that CAPEX costs are expected to reach 1€/W in 2023, and this 10% dropped price is the one used in the financial model, leading to a CAPEX requirement of 40.000.000€ for the investment.

Similar to the previous example, VAT is not used or calculated in the CAPEX cost, as it is considered fully refundable, while for the WTG not payable at all, and any interest of a possible tranche that would finance it could be safely paid by the contingency amount.

4.3.4. Operational Expenses

The Operational expenses to be considered in the financial model, slightly differ from the ones of the previous example, due to their dependence from some income parameters.

WTG O&M prices are expected to be more competitive than the ones introduced in the previous example, due to technology optimization and follow the trend tabulated below.

Years	Fee per WTG (€)	Total fee (€)
1-5	40.000,00	400.000,00
6-10	50.000,00	500.000,00
10-15	55.000,00	550.000,00
16-20	60.000,00	600.000,00

Table 4-10

Regarding the remaining operational expenses, BOP maintenance is expected to be reduced to 30.000€/year and S/S maintenance to 25.000€/year. The remaining costs are calculated as described in the previous example.

Furthermore, due to the uncertainty of the power price, a price hedging in the energy futures market is expected to be requested by the financing institutions. The amount of this hedging cost is estimated at 5%, since according to Botterud, Kristiansen, & Ilic (Botterud, Kristiansen, & Ilic, 2010) the range of the risk premium is between 1,3% to 4,4% and increases with the holding period. The same cost can be assumed as a discount on the average spot price, offered to an energy offtaker in order to sign a long term PPA.

Overall OPEX cost reaches 1.050.000€ for the first year of operation, which is higher than the one assumed in the FiP example, regardless of the reduction of the O&M costs, due to the 5% hedging cost.

4.3.5. Financial Parameters

The financial model was initially examined with exactly the same parameters as in the FiP example, while because it showed a DSCR for the first 3 years below 1,3, capital repayment profile was sculptured, while an additional scenario was examined with fixed debt payments for the whole period.

4.3.6. Financial Model

Once again the financial model was prepared as in the FiP example for a 20 year duration. It should be noted that new wind turbines are expected to enjoy a lifetime of 25 years or even 30, rather than 20 (Wiser & Bolinger, 2019), therefore, since there was no 20 year incentive scheme as a limitation in this case, 25 years of operational time was also examined. Once again, the results of year one are presented below, and the full 20 year period rounded in k€, in the following table.

Year	**1**
Power price	36,33€
Income	3.818.827€
OPEX	1.050.880€
levies	114.565€
EBITDA	2.653.383€
Capital debt	30.000.000€
Capital repayment	1.500.000€
Interest	1.110.000€
Debt service	2.610.000€
Depreciation	2.000.000€
EBT	-456.617€
Income tax	€
CFADS	2.653.383€
Net result	-456.617€
FCFE	43.383€

Table 4-11

	Wind Farm within the Target model financial model																			
																				Sums in .000€
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Calendar Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Power price	0,036	0,040	0,043	0,046	0,049	0,052	0,054	0,057	0,059	0,059	0,055	0,053	0,056	0,056	0,052	0,048	0,040	0,041	0,044	0,042
Income	3.819	4.181	4.520	4.882	5.115	5.430	5.687	6.003	6.213	6.213	5.745	5.605	5.897	5.921	5.430	5.044	4.168	4.331	4.659	4.413
OPEX	1.051	1.071	1.089	1.109	1.122	1.168	1.183	1.200	1.212	1.212	1.233	1.225	1.242	1.243	1.216	1.213	1.165	1.174	1.192	1.178
levies	115	125	136	146	153	163	171	180	186	186	172	168	177	178	163	151	125	130	140	132
EBITDA	2.653	2.985	3.295	3.626	3.839	4.099	4.334	4.623	4.815	4.815	4.340	4.212	4.479	4.500	4.051	3.680	2.878	3.028	3.327	3.102
Capital debt	30.000	28.500	27.000	25.500	24.000	22.500	21.000	19.500	18.000	16.500	15.000	13.500	12.000	10.500	9.000	7.500	6.000	4.500	3.000	1.500
Capital repayment	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500
Interest	1.110	1.055	999	944	888	833	777	722	666	611	555	500	444	389	333	278	222	167	111	56
Debt service	2.610	2.555	2.499	2.444	2.388	2.333	2.277	2.222	2.166	2.111	2.055	2.000	1.944	1.889	1.833	1.778	1.722	1.667	1.611	1.556
Depreciation	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000
EBT	-457	-70	296	682	951	1.267	1.557	1.901	2.149	2.205	1.785	1.712	2.035	2.112	1.718	1.402	656	861	1.216	1.047
Losses carried forward	-	-457	-526	-231	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income tax	-	-	71	164	228	304	374	456	516	529	428	411	488	507	412	337	157	207	292	251
CFADS	2.653	2.985	3.224	3.462	3.611	3.795	3.960	4.166	4.299	4.286	3.912	3.801	3.990	3.993	3.639	3.343	2.720	2.821	3.035	2.851
Net result	-457	-70	225	519	723	963	1.183	1.445	1.633	1.675	1.357	1.301	1.546	1.605	1.306	1.066	498	654	924	796
FCFE	43	430	725	1.019	1.223	1.463	1.683	1.945	2.133	2.175	1.857	1.801	2.046	2.105	1.806	1.566	998	1.154	1.424	1.296

Table 4-12

Once again the following modelling indicators were calculated:

LCOE@WACC	43,25 €
LCOE@10%	60,96 €
LCOE@7,5%	52,74 €
NPV equity	2.653.526,30 €
NPV project	9.133.864,80 €
equity IRR	11,54%
project IRR	6,65%

Table 4-13

From the calculated indicators we derive the following:

LCOE of the project of 43,25€/MWh is below the average Power price of 49,12 €/MWh, that would be indicating an over-remunerated project.

Positive NPV for equity and overall project are also calculated, since equity and project IRRs are both above the estimated cost of equity and WACC respectively. The high equity IRR compared to the cost of equity is mainly due to the high equity gearing ratio.

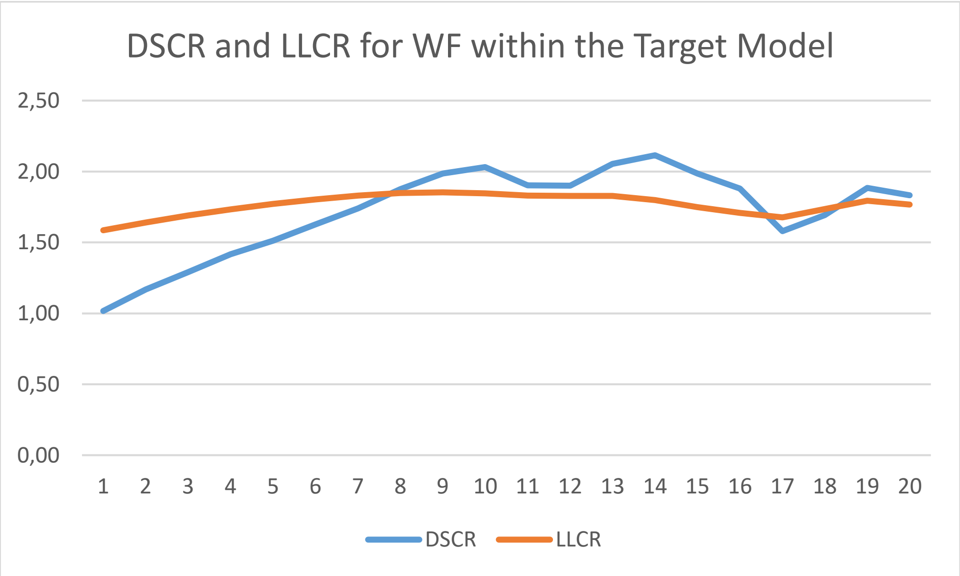
4.3.7. Financing

The financing of the investment is again assessed as project finance in a non-recourse basis and DSCR and LLCR ratios were calculated, as follows.

Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
DSCR	1,02	1,17	1,29	1,42	1,51	1,63	1,74	1,88	1,98	2,03	1,90	1,90	2,05	2,11	1,99	1,88	1,58	1,69	1,88	1,83
LLCR	1,59	1,64	1,69	1,73	1,77	1,80	1,83	1,85	1,85	1,84	1,83	1,83	1,83	1,80	1,75	1,71	1,68	1,74	1,79	1,77

Table 4-14

And were again inserted in a diagram to indicate their trend in time.

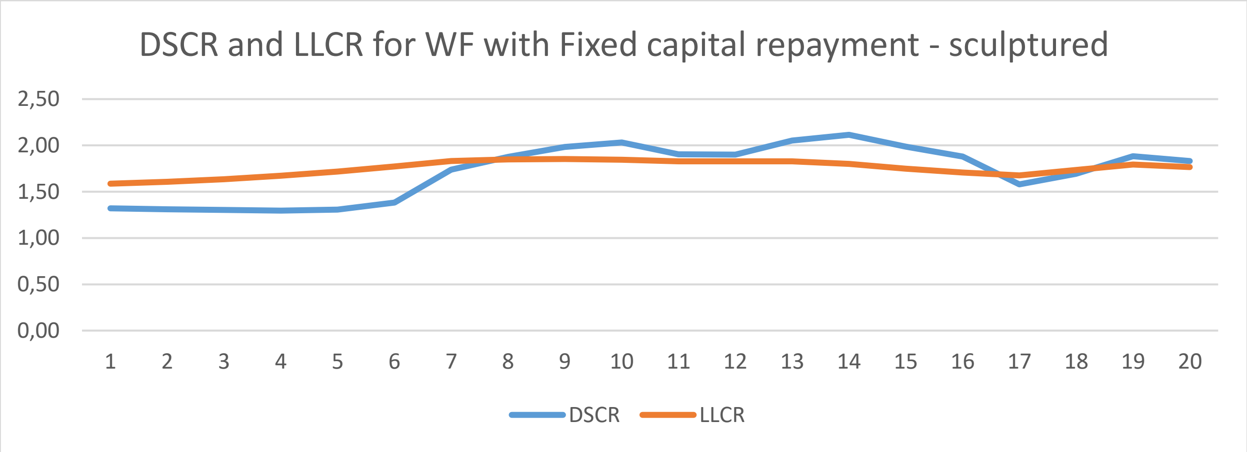


Graph 4-5

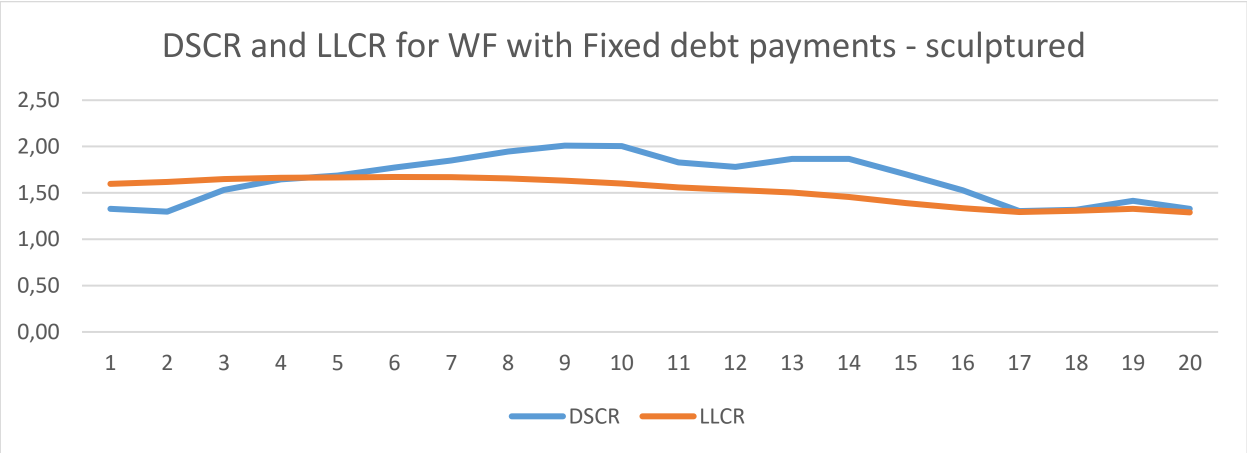
In comparison with the FiP example, a low (and unacceptable) DSCR is identified for the first three years, due to the low estimated Power price then. DSCR is above 1,3 only at the 4th year and rises to above 2 on year 10, while LLCR is above 1,5 from the beginning. This indicates that a small sculpturing of the capital repayment profile for the first 3 years would be adequate to render the loan acceptable by the financing organizations.

Capital repayment was reduced in these years by 600.000€, 300.000€ and 50.000€ respectively and repayment by an additional sum of 200.000, 350.000, 400.000 was adjusted in years 4 to 6. With this sculpturing, DSCR reached at least 1.30 in all cases.

Another solution examined, was to change the repayment method of the loan to fixed payments of 2.150.000€ for the whole period. This solution also required a slight sculpturing, by deferring 150.000€ of the first payment period to the second, in order to keep DSCR above 1,30 in all cases, as well as prepaying 50.000€ of year's 17 capital in year 16. Both examined scenarios are tabulated below, included DSCR and LLCR ratios achieved.



Graph 4-6



Graph 4-7

	Wind Farm within the Target model financial model – sculptured capital repayment profile																			
	Sums in .000€																			
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Calendar Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Power price	0,036	0,040	0,043	0,046	0,049	0,052	0,054	0,057	0,059	0,059	0,055	0,053	0,056	0,056	0,052	0,048	0,040	0,041	0,044	0,042
Income	3.819	4.181	4.520	4.882	5.115	5.430	5.687	6.003	6.213	6.213	5.745	5.605	5.897	5.921	5.430	5.044	4.168	4.331	4.659	4.413
OPEX	1.051	1.071	1.089	1.109	1.122	1.168	1.183	1.200	1.212	1.212	1.233	1.225	1.242	1.243	1.216	1.213	1.165	1.174	1.192	1.178
levies	115	125	136	146	153	163	171	180	186	186	172	168	177	178	163	151	125	130	140	132
EBITDA	2.653	2.985	3.295	3.626	3.839	4.099	4.334	4.623	4.815	4.815	4.340	4.212	4.479	4.500	4.051	3.680	2.878	3.028	3.327	3.102
Capital debt	30.000	29.100	27.900	26.450	24.750	22.900	21.000	19.500	18.000	16.500	15.000	13.500	12.000	10.500	9.000	7.500	6.000	4.500	3.000	1.500
Capital repayment	900	1.200	1.450	1.700	1.850	1.900	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500
Interest	1.110	1.077	1.032	979	916	847	777	722	666	611	555	500	444	389	333	278	222	167	111	56
Debt service	2.010	2.277	2.482	2.679	2.766	2.747	2.277	2.222	2.166	2.111	2.055	2.000	1.944	1.889	1.833	1.778	1.722	1.667	1.611	1.556
Depreciation	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000
EBT	-457	-92	262	647	924	1.252	1.557	1.901	2.149	2.205	1.785	1.712	2.035	2.112	1.718	1.402	656	861	1.216	1.047
Losses carried forward	-	-457	-549	-286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income tax	-	-	63	155	222	300	374	456	516	529	428	411	488	507	412	337	157	207	292	251
CFADS	2.653	2.985	3.232	3.470	3.618	3.799	3.960	4.166	4.299	4.286	3.912	3.801	3.990	3.993	3.639	3.343	2.720	2.821	3.035	2.851
Net result	-457	-92	199	492	702	951	1.183	1.445	1.633	1.675	1.357	1.301	1.546	1.605	1.306	1.066	498	654	924	796
FCFE	643	708	749	792	852	1.051	1.683	1.945	2.133	2.175	1.857	1.801	2.046	2.105	1.806	1.566	998	1.154	1.424	1.296
DSCR	1,32	1,31	1,30	1,30	1,31	1,38	1,74	1,88	1,98	2,03	1,90	1,90	2,05	2,11	1,99	1,88	1,58	1,69	1,88	1,83
LLCR	1,59	1,61	1,64	1,67	1,72	1,77	1,83	1,85	1,85	1,84	1,83	1,83	1,83	1,80	1,75	1,71	1,68	1,74	1,79	1,77

Table 4-15

	Wind Farm within the Target model financial model – fixed payments and sculptured capital repayment profile																			
																				Sums in .000€
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Calendar Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Power price	0,036	0,040	0,043	0,046	0,049	0,052	0,054	0,057	0,059	0,059	0,055	0,053	0,056	0,056	0,052	0,048	0,040	0,041	0,044	0,042
Income	3.819	4.181	4.520	4.882	5.115	5.430	5.687	6.003	6.213	6.213	5.745	5.605	5.897	5.921	5.430	5.044	4.168	4.331	4.659	4.413
OPEX	1.051	1.071	1.089	1.109	1.122	1.168	1.183	1.200	1.212	1.212	1.233	1.225	1.242	1.243	1.216	1.213	1.165	1.174	1.192	1.178
levies	115	125	136	146	153	163	171	180	186	186	172	168	177	178	163	151	125	130	140	132
EBITDA	2.653	2.985	3.295	3.626	3.839	4.099	4.334	4.623	4.815	4.815	4.340	4.212	4.479	4.500	4.051	3.680	2.878	3.028	3.327	3.102
Capital debt	30.000	29.110	27.887	26.769	25.609	24.407	23.160	21.867	20.526	19.135	17.693	16.198	14.647	13.039	11.372	9.643	7.799	5.988	4.059	2.060
Capital repayment	890	1.223	1.118	1.160	1.202	1.247	1.293	1.341	1.391	1.442	1.495	1.551	1.608	1.668	1.729	1.843	1.811	1.928	2.000	2.074
Interest	1.110	1.077	1.032	990	948	903	857	809	759	708	655	599	542	482	421	357	289	222	150	76
Debt service	2.000	2.300	2.150	2.150	2.150	2.150	2.150	2.150	2.150	2.150	2.150	2.150	2.150	2.150	2.150	2.200	2.100	2.150	2.150	2.150
Depreciation	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000
EBT	-457	-92	263	635	892	1.196	1.477	1.814	2.056	2.107	1.685	1.612	1.937	2.018	1.630	1.323	589	806	1.177	1.026
Losses carried forward	-	-457	-549	-286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income tax	-	-	-	84	214	287	355	435	493	506	404	387	465	484	391	318	141	193	282	246
CFADS	2.653	2.985	3.295	3.542	3.625	3.812	3.980	4.187	4.322	4.309	3.935	3.825	4.014	4.016	3.660	3.362	2.736	2.834	3.044	2.856
Net result	-457	-92	263	552	678	909	1.123	1.378	1.562	1.601	1.281	1.225	1.472	1.533	1.239	1.005	448	613	894	780
FCFE	653	685	1.145	1.392	1.475	1.662	1.830	2.037	2.172	2.159	1.785	1.675	1.864	1.866	1.510	1.162	636	684	894	706
DSCR	1,33	1,30	1,53	1,65	1,69	1,77	1,85	1,95	2,01	2,00	1,83	1,78	1,87	1,87	1,70	1,53	1,30	1,32	1,42	1,33
LLCR	1,60	1,62	1,65	1,66	1,67	1,67	1,67	1,66	1,63	1,60	1,56	1,53	1,50	1,46	1,39	1,33	1,30	1,31	1,33	1,29

Table 4-16

The following modelling indicators were again calculated:

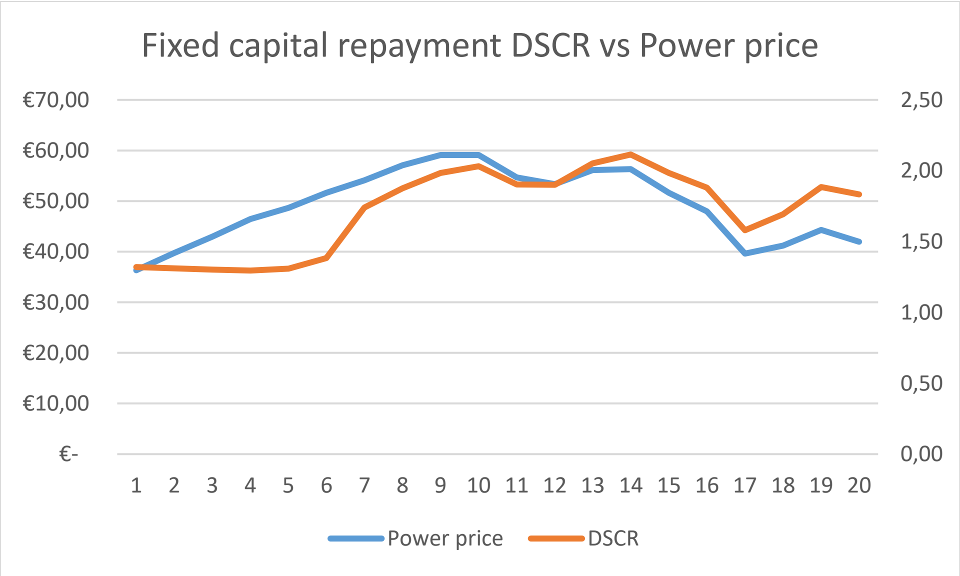
	Fixed capital payments - sculptured	Fixed debt payments - sculptured
LCOE@WACC	47,81 €	48,34 €
LCOE@10%	64,32 €	64,77 €
LCOE@7,5%	56,65 €	57,14 €
NPV equity	1.835.243,63 €	2.683.800,50 €
NPV project	6.551.533,07 €	6.839.590,27 €
equity IRR	11,05%	12,31%
project IRR	6,15%	6,23%

Table 4-17

By comparing the two (acceptable) financing solutions, the fixed debt payment profile is better for the investor, by adding ~800.000€ to the equity NPV and achieving a higher equity IRR by 1,25%. This is mainly caused due to the payment of larger sums in the future in the second case, which brings forward more dividend distribution. Overall project NPV and IRR are only slightly affected, due to the minor additional interest paid.

LCOEs in these case become comparable to the average tariff of 49,12€/MWh, indicated fair remuneration of produced energy.

Compared to the FiP example in which the DSCR and LLCR ratios experienced a steady upward trend, in this case the metrics followed the Power price variation, as shown in the graph below. Initial years' difference is only due to the debt repayment sculpturing.



Graph 4-8

In an attempt to decrease the loan tenor to 15 years, heavier sculpturing was required, by deferring parts of capital payments up to the 3rd or 5th year and repaying them up to the 8th or 12th year (for fixed debt payments and fixed capital payments accordingly), while equity IRR dropped close to 10%.

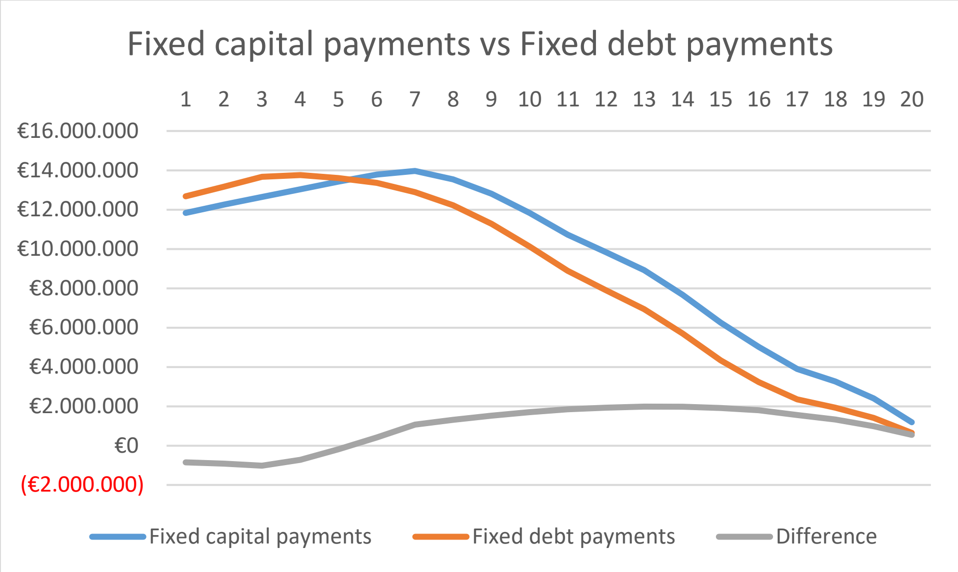
4.3.8. Valuation

The valuation method followed was the same as in the FiP case, by using the discounted cash flow appraisal.

The values calculated at each year, are presented below.

	Fixed capital payments	Fixed debt payments	
Year	**Valuation**	**Valuation**	**Difference**
1	11.835.244 €	12.683.801 €	-848.557 €
2	12.257.032 €	13.171.959 €	-914.927 €
3	12.652.244 €	13.672.814 €	-1.020.570 €
4	13.041.660 €	13.758.850 €	-717.190 €
5	13.423.609 €	13.605.136 €	-181.526 €
6	13.779.709 €	13.354.192 €	425.517 €
7	13.968.556 €	12.894.061 €	1.074.495 €
8	13.542.331 €	12.224.951 €	1.317.380 €
9	12.816.264 €	11.287.802 €	1.528.462 €
10	11.836.470 €	10.132.016 €	1.704.454 €
11	10.726.314 €	8.884.557 €	1.841.757 €
12	9.835.131 €	7.898.699 €	1.936.432 €
13	8.919.103 €	6.934.933 €	1.984.170 €
14	7.675.371 €	5.695.117 €	1.980.254 €
15	6.261.303 €	4.341.777 €	1.919.526 €
16	5.019.072 €	3.222.727 €	1.796.345 €
17	3.905.077 €	2.350.535 €	1.554.542 €
18	3.258.109 €	1.925.680 €	1.332.429 €
19	2.396.972 €	1.414.912 €	982.060 €
20	1.188.630 €	647.777 €	540.853 €

Table 4-18



Graph 4-9

The valuation examination showed the same as the NPV and IRR indicators, namely the higher value of the investment in the beginning for the fixed debt payment profile, which gradually reduces in time and remains beneath the fixed capital payment profile after year five. It should be noted that the increase in value for the first years, although the project is producing cashflows to the equity holder, comes into opposition with the valuation trend of the project remunerated through a fixed FiP. This is caused due to the expected upwards trend of the power price, for the initial few years, as well as the deferring of some initial debt payments and carrying forward initial losses, that reduce early project value.

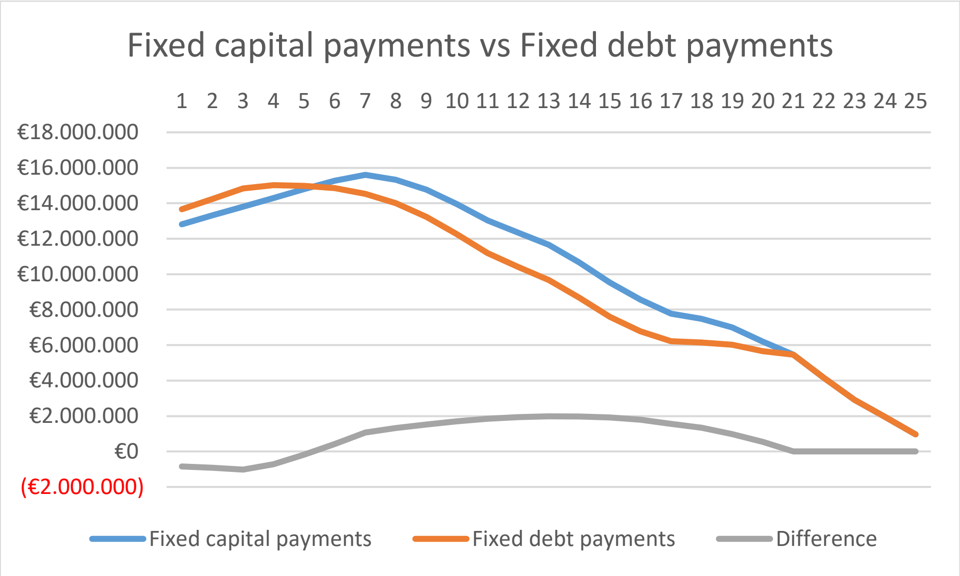
This investment was also examined for a 25 year lifetime, which adds value of the income acquired after the 20th year, since by then debt is considered repaid. Depreciation could also be extended to 25 years rather than 20, nevertheless, for comparison reasons it was not changed.

The result is an additional value transposed by the present value of the expected 5-year additional cashflow, with no difference between the two debt repayment profiles.

	Fixed capital payments	Fixed debt payments	Debt payment method	25 years vs 20 years operation
Year	Valuation	Valuation	Difference	Difference
1	12.809.864 €	13.658.421 €	-848.557 €	974.620 €
2	13.319.368 €	14.234.295 €	-914.927 €	1.062.336 €
3	13.810.190 €	14.830.761 €	-1.020.570 €	1.157.946 €
4	14.303.822 €	15.021.011 €	-717.190 €	1.262.161 €
5	14.799.365 €	14.980.891 €	-181.526 €	1.375.756 €

6	15.279.283 €	14.853.765 €	425.517 €	1.499.574 €
7	15.603.092 €	14.528.596 €	1.074.495 €	1.634.536 €
8	15.323.974 €	14.006.594 €	1.317.380 €	1.781.644 €
9	14.758.255 €	13.229.793 €	1.528.462 €	1.941.992 €
10	13.953.241 €	12.248.787 €	1.704.454 €	2.116.771 €
11	13.033.594 €	11.191.838 €	1.841.757 €	2.307.280 €
12	12.350.067 €	10.413.634 €	1.936.432 €	2.514.936 €
13	11.660.383 €	9.676.213 €	1.984.170 €	2.741.280 €
14	10.663.366 €	8.683.112 €	1.980.254 €	2.987.995 €
15	9.518.217 €	7.598.691 €	1.919.526 €	3.256.914 €
16	8.569.109 €	6.772.764 €	1.796.345 €	3.550.037 €
17	7.774.617 €	6.220.075 €	1.554.542 €	3.869.540 €
18	7.475.907 €	6.143.478 €	1.332.429 €	4.217.799 €
19	6.994.372 €	6.012.312 €	982.060 €	4.597.401 €
20	6.199.797 €	5.658.944 €	540.853 €	5.011.167 €
21	5.462.172 €	5.462.172 €	0 €	5.462.172 €
22	4.162.125 €	4.162.125 €	0 €	4.162.125 €
23	2.915.716 €	2.915.716 €	0 €	2.915.716 €
24	1.955.295 €	1.955.295 €	0 €	1.955.295 €
25	965.316 €	965.316 €	0 €	965.316 €

Table 4-19



Graph 4-10

The valuation examination in year 1 shows an 18% gain on equity for the 20year/fixed capital payments example, which reaches 37% for the 25year/fixed debt payments profile, which is similar to the Wind Farm with a FiP's example of 40%.

5. PV station case study

5.1. Introduction

This case study assesses the financing possibilities and valuation parameters of a photovoltaic station, to be constructed within similar frameworks as the wind farm, that is within current incentive schemes as well as within the aid-free options of the Target Model.

The case to be examined shall be of a PV station installed in the Greek mainland with parameters as close as possible to the typical ones. The station will be of a fixed type with an expected yield of 1.600kWh/kW, which is a typical value for southern Greece with bifacial PV panels. Although single axis trackers are also commonly used wherever possible, for reasons of simplicity only the fixed mounting structure case was examined.

Similar to wind farms, yield is usually calculated with exceedance probability scenarios (commonly P50-P75-P90), based on the various solar database used, equipment and other uncertainties. Further analysis is not part of this document, therefore whenever a yield is used, it is considered as the one with exceedance probabilities acceptable to the entity examining the investment.

The size of the pv station will be one of 40MWp, to allow for better allocation of the fixed costs of the grid connection.

Grid connection is considered with a new 33/150kV substation within a distance of 5km from the PV station, situated under an existing 150kV line, in order to avoid HV line routing. The reason a shorter distance was assumed compared to the 10km of the wind farm, was that the latter are commonly constructed on mountain tops, away from the transmission grid, while PV stations are constructed closer to the transmission grid.

5.2. PV station with FiP

The inputs to be considered in the financial model for a PV station with a FiP incentive scheme are divided as in the Wind farm case in four categories, namely

- ✓ Capital expenses – CAPEX
- ✓ Income
- ✓ Operational expenses – OPEX
- ✓ Financial parameters

As analyzed in the respective paragraphs.

5.2.1. Incentive framework

The incentive framework assessed is this case is once again the Sliding Premium (FiP) above the market spot price, which assures that the investment is remunerated with a more-or-less fixed price (the Reference Price), as described in chapter 3.5.2. and allows us to model the expected cash inflow also in this case with significant accuracy, with the only variable being the actual production yield.

5.2.2. Income

The income to be considered in the financial model is calculated as the product of estimated electricity production by the FiP price.

As explained earlier, PV stations in southern Greece achieve a yield of 1600kWh/kWp in average, while modern bifacial panels have a degradation factor of 0,5%, therefore the produced energy for a 40MWp PV station shall be for the first year:

40MWp*1600kWh/kWp=64.000MWh. For each year thereafter, the yield will drop 0,5% annually. It should be noted that the LID phenomenon has already been incorporated in the 1600kWh/kW figure.

The remuneration price, as per RAE's July 2020 tender was 49,81 €/MWh on average (Regulatory Authority of Energy, 2020), therefore this is what we shall consider.

Conclusively, first year income of the PV station shall be 3.187.840,00€, while 3.040.865,27€ shall be earned for the 20 years on an average basis.

5.2.3. Capital Expenses

The Capital expenses to be considered refer to the investment cost and include all necessary expenditures to develop, construct and commission a fully operational PV station with the characteristics described above.

The CAPEX cost per installed capacity is estimated as 0,63€/W, as per current market and is divided for a 40MWp PV station as follows.

Cost category	Cost
Development - studies	500.000 €
EPC contract	18.800.000 €
S/S	3.500.000 €
MV grid - external	600.000 €
Construction Supervision	300.000 €
Other costs	115.000 €
Financing costs - arrangement fee	185.000 €
IDC	690.000 €

Contingencies	310.000 €
TOTAL	**25.000.000 €**

Table 5-1

The cost for the development, full permitting and performance of the implementation studies is considered at 500.000€, which is within current market standards.

The cost of the PV station EPC contract, including equipment procurement, erection and commissioning is estimated at 0,47€/Wp, which is currently the prevailing market price for fixed PVs.

The cost for the HV substation is once again considered at the average market price, with the assumption that no HV line will be built and a 40/50MVA transformer will be installed. It should be mentioned that quite frequently other RES projects acquire grid connection terms for the same substation and participate in these common connection works, however in this case no cost sharing is assumed.

The cost of the external MV grid, from the PV station to the S/S is estimated at 40.000€/km for the routing earthworks, as well as 40.000€/km for each MV circuit with a capacity of 20MWp. Conclusively, the cost for the 5km of the network is expected to reach 600.000€.

Additionally a sum of 300.000€ is considered for construction supervision and quality control on behalf of the investor, as well as 115.000€ for other costs. It should be noted that PV stations are commonly constructed in either public forestry land (grassland) and pay a once-off consideration for the land and reforest an equal area, or within municipal, ministry of agriculture or private land and pay an annual consideration. The latter case with annual payments was assumed, and inserted in the OPEX provisions. A sum of 310.000€ is also considered as construction contingencies.

Additionally, a Financing costs and arrangement fee of 185.000€ is considered, as well as capitalized interest during construction (considering one year construction period due to the HV substation) at 690.000€.

VAT is not used or calculated in the CAPEX cost, as it is considered fully refundable, while for the PV equipment not payable at all, and any interest of a possible tranche that would finance it could be safely paid by the contingency amount.

5.2.4. Operational Expenses

The Operational expenses to be considered in the financial model are approx. 19% of income for the first year and are divided as follows.

Cost category	Cost (€)
O&M fee	240.000,00
Spare parts	24.000,00
S/S maintenance	30.000,00
Land	15.000,00
Insurance	53.005,68
Aggregator fee	96.000,00
ARESGO fee	20.800,00
Electricity consumption	9.563,52
Personnel cost	50.000,00
Admnistrative expenses	50.000,00
TOTAL	**600.000,00**

Table 5-2

The cost for the annual equipment maintenance is estimated at 6.000€/MWp in an annual basis, as well as a figure of 10% for spare parts or inverter warranty extension. The substation preventive maintenance cost is estimated at 30.000€ per year, as per market practice and annual land lease costs were assumed at 15.000€.

The insurance cost for machinery breakdown and loss of profit is estimated at 0,2% of the insured capital, that is the construction cost (CAPEX cost minus development and financial costs) as well as the annual income.

The aggregator fee is expected to be 1,5€/MWh, therefore 96.000,00€ for the expected yield of 64.000MWh, while the fee of ARESGO was set for 2021 at 0,325€/MWh resulting in a total fee of 20.800,00€.

The cost of consumed electricity at hours on non-production is estimated at 0,3% of income, while personnel cost and administrative expenses at 50.000€ each, on an annual basis. An additional contingency amount of 11.630,80€ is considered, summing up the total OPEX costs for the first year at 600.000,00€.

It should also be mentioned that a levy of 3% is payable from all RES producers (except PVs unless participating in a technology neutral RAE tender) to the local municipality. This cost is not included in the OPEX sum but considered separately in the financial model. For PV stations of 40MWp such as the one under examination, usually compete in technology neutral RAE tenders, therefore this levy has been considered in the model.

5.2.5. Financial Parameters

Similar to the Wind Farms, for PV stations with a secured FiP where the amount of income is considered more or less secured, Lenders commonly participate in project financing on a non-recourse basis, undertaking up to 75-80% of the investment cost, as long as the Debt Service Coverage Ratio (DSCR) is kept above 1,3-1,4 during the tenor of the loan.

In the case examined, once again a LTC ratio of 75% is selected, while DSCR is checked for various tenor periods, up to 20 years. The loan interest considered is 3,7% while the repayment method shall be annual interest payment as well as equal capital repayments.

An arrangement fee including various financing costs at 1% of the loan is considered, as well as capitalized interest during the construction period, which in this case is considered one year. Lenders also commonly finance DSRA, OPEXRA and MRA accounts, but in this case their costs are considered included in the estimated interest.

A CPI of 0,5% is also considered, regarding the indexation of OPEX costs.

The cost of equity is considered 9%, resulting in a WACC of 25%*0,09+75%*0,037*(1-24%)=4,36%. Regarding tax, an income tax of 24% is considered, as well as a straight line depreciation period of 20 years.

5.2.6. Financial model

The financial model was prepared in an excel sheet for the 20 years of the expected FiP contract duration.

For the first year, the following calculation method was followed.

Income was calculated as per par. 5.2.2, while operational expenses and levies as per par. 5.2.4. The EBITDA was calculated by subtracting OPEX and levies from the income. The Capital debt at the beginning of the financial model equals the project's financed CAPEX (75%) as per par. 5.2.3, while the capital repayment sum was capital debt divided by the loan tenor (i.e. 20 years). The accrued interest was calculated upon the outstanding debt, while the debt service is the sum of capital repayment and accrued interest. The depreciation was the quotient of CAPEX divided by the depreciation period of 20 years, while EBT was calculated by subtracting from EBITDA the interest paid and the depreciation. Income tax was calculated by multiplying the tax rate with EBT, while CFADS was calculated by subtracting income tax from EBITDA. The net result was calculated as the difference of EBT and income tax, while for the FCFE calculation, Debt service and tax are deducted from EBITDA. The results of the first year are tabulated below, while for the 20-year operating period in the following table, where sums are rounded in k€ in order to fit the page.

Year	1
Income	3.187.840,00 €
OPEX	600.000,00 €
levies	95.635,20 €
EBITDA	2.492.205 €
Capital debt	18.750.000 €
Capital repayment	937.500 €
Interest	693.750 €
Debt service	1.631.250 €
Depreciation	1.250.000 €
EBT	548.455 €
Income tax	131.629 €
CFADS	2.360.576 €
Net result	416.826 €
FCFE	729.326 €

Table 5-3

	PV station with FiP financial model																			
	Sums in .000€																			
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Income	3.188	3.172	3.156	3.140	3.125	3.109	3.093	3.078	3.063	3.047	3.032	3.017	3.002	2.987	2.972	2.957	2.942	2.927	2.913	2.898
OPEX	600	606	612	618	624	631	637	643	650	656	663	669	676	683	690	697	704	711	718	725
levies	96	95	95	94	94	93	93	92	92	91	91	91	90	90	89	89	88	88	87	87
EBITDA	2.492	2.471	2.449	2.428	2.406	2.385	2.364	2.342	2.321	2.300	2.278	2.257	2.236	2.214	2.193	2.172	2.150	2.129	2.108	2.086
Capital debt	18.750	17.813	16.875	15.938	15.000	14.063	13.125	12.188	11.250	10.313	9.375	8.438	7.500	6.563	5.625	4.688	3.750	2.813	1.875	937
Capital repayment	938	938	938	938	938	938	938	938	938	938	938	938	938	938	938	938	938	938	938	938
Interest	694	659	624	590	555	520	486	451	416	382	347	312	278	243	208	173	139	104	69	35
Debt service	1.631	1.597	1.562	1.527	1.493	1.458	1.423	1.388	1.354	1.319	1.284	1.250	1.215	1.180	1.146	1.111	1.076	1.042	1.007	972
Depreciation	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250
EBT	548	562	575	588	601	615	628	641	655	668	681	695	708	721	735	748	762	775	788	802
Income tax	132	135	138	141	144	148	151	154	157	160	164	167	170	173	176	180	183	186	189	192
CFADS	2.361	2.336	2.311	2.287	2.262	2.238	2.213	2.188	2.164	2.139	2.115	2.090	2.066	2.041	2.017	1.992	1.968	1.943	1.919	1.894
Net result	417	427	437	447	457	467	477	487	498	508	518	528	538	548	558	569	579	589	599	609
FCFE	729	739	749	760	770	780	790	800	810	820	830	840	851	861	871	881	891	901	912	922

Table 5-4

The following modelling indicators were calculated:

LCOE@WACC	49,69 €
LCOE@10%	66,78 €
LCOE@7,5%	58,85 €
NPV equity	1.031.848,64€
NPV project	3.463.644,14€
equity IRR	11,14%
project IRR	5,96%

Table 5-5

From the calculated indicators we derive the following:

LCOE of the project of 49,69€/MWh is very close to the FiP used of 49,81 €/MWh, indicating a balanced financial model and fair remuneration of energy. It should be noted that in many cases LCOE is also calculated with a 10% discount rate or a 7,5% discount rate, in order to be comparable with international investments.

Positive NPV for equity and overall project are calculated, since equity and project IRRs are both above the estimated cost of equity and WACC respectively. The high equity IRR compared to the cost of equity is mainly due to the high equity gearing ratio.

5.2.7. Financing

The financing of the investment could either be performed by full equity, by issuing a corporate bond loan, or by project finance in a non-recourse basis.

The latter form of financing the investment is the most commonly encountered in Greece, due to current low interest rates, high tax rates and a favorably high gearing ratio which leads to very low WACC.

The metric mostly examined by financial institutions is the Debt Service Coverage Ratio (DSCR), which is the Cash flow Available for Debt Service (CFADS) divided by the Debt Service (Capital repayment plus interest) for each examined period (commonly year).

Another ratio examined is the Loan Life Coverage Ratio (LLCR), which is the NPV of all future free cashflow available for debt service at any given time, divided by the debt balance at that time.

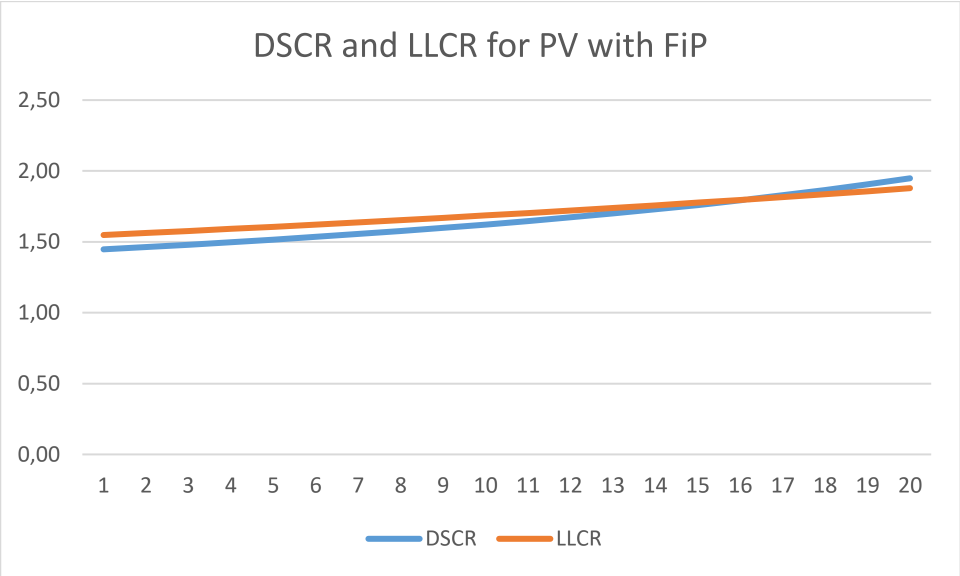
Most commonly targeted DSCR ratio is 1,3x (at P90) and 1,2x (at P99) as per (Pacudan, 2016). For Greek banks the relevant ratio is 1.3x at P75. The same ratio shall be set as a target for the LLCR.

From the financial model examined the relevant ratios were calculated as follows:

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DSCR	1,45	1,46	1,48	1,50	1,52	1,53	1,55	1,58	1,60	1,62	1,65	1,67	1,70	1,73	1,76	1,79	1,83	1,87	1,91	1,95
LLCR	1,55	1,56	1,58	1,59	1,61	1,62	1,64	1,65	1,67	1,69	1,70	1,72	1,74	1,76	1,78	1,80	1,82	1,84	1,86	1,88

Table 5-6

And were inserted in a diagram to indicate their trend in time.



Graph 5-1

Their positive trend in time as well as their significant distance from the 1.3x threshold, as well as the certainty of the expected income due to the secured FiP justifies the high gearing ratio and the long loan maturity periods offered.

By examining the possibility of shorter loan maturity periods, the 1.3x threshold is met at approx. 17 years. Once again, due to the upward trend of the ratios, minor debt sculpturing would allow ever shorter tenors.

5.2.8. Valuation

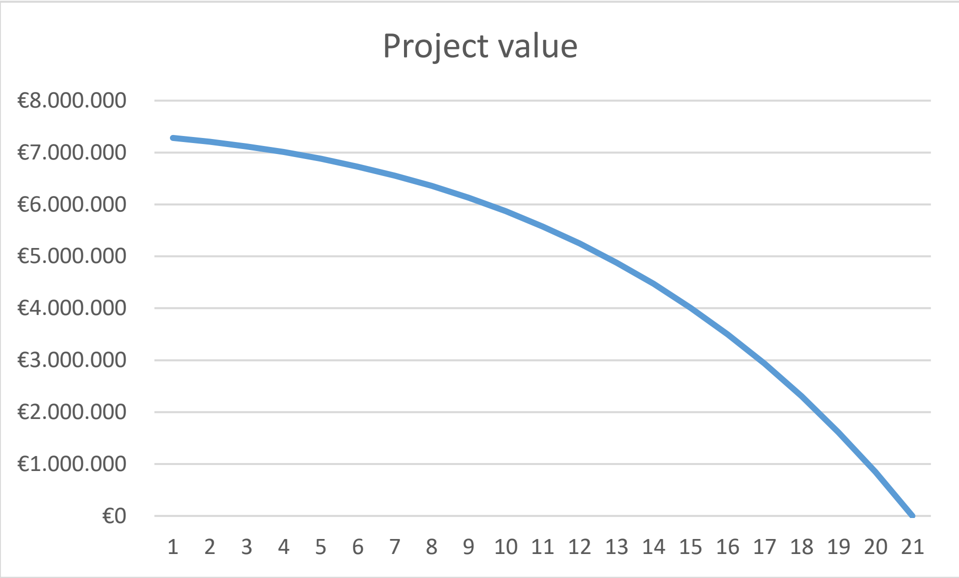
In order to valuate the investment and assess the fair price at which it could be acquired by a potential investor at any given period of time, once again the discounted cash flow appraisal is used.

Similar to the Wind farm, FCFE for each year is calculated, and then discounted using the equity return rate of 9% for each year forward from the year examined.

The values calculated at each year, are presented below.

Year	Valuation
1	7.281.848,64€
2	7.207.889,37€
3	7.117.221,65€
4	7.008.328,55€
5	6.879.557,40€
6	6.729.107,52€
7	6.555.016,94€
8	6.355.147,85€
9	6.127.170,81€
10	5.868.547,52€
11	5.576.511,96€
12	5.248.049,97€
13	4.879.876,88€
14	4.468.413,18€
15	4.009.758,00€
16	3.499.660,16€
17	2.933.486,67€
18	2.306.188,38€
19	1.612.262,48€
20	845.711,75€

Table 5-7



Graph 5-2

The debt has not been factored in the above estimation, meaning that a potential investor would need of course to undertake the debt of the project at any time of acquisition.

Additionally, the project is considered to have no value at the end of its lifetime, while decommissioning costs are expected to be set-off by the salvage value of the equipment.

From the above table it is easily determined that the project has an initially high value, close to 7,3M€ and retains it in such levels up to its 4th year of operation. A continuous downwards value trend is identified in this example, which gets steeper in time.

In year one, if the investor decided to sell the project, he would gain 1.031.848,64 € above his invested equity of 6.250.000€, that is almost 17%. The reason this sum is almost half of the gain in Wind farms, is because PV station development and construction is easier than Wind, also resulting in lower prices in the tender process.

5.3. PV station within the Target model

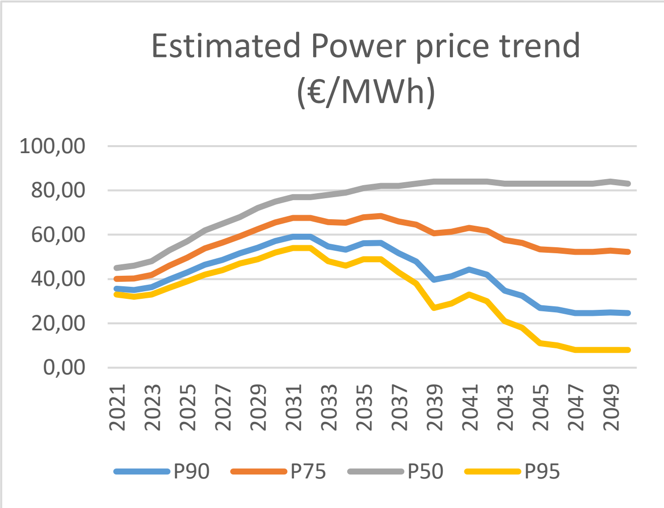
The inputs to be considered in the financial model for a PV station within the Target model era, that is with no incentive scheme are once again divided in the same four categories, as before and analyzed in the respective paragraphs. Year 2023 is considered as the examined year, since by that time, incentive schemes are expected to be reduced, if not ended.

5.3.1. Remuneration framework

The remuneration framework and prices shall be the same both for PV and Onshore Wind, therefore the same prices as in the Onshore Wind in the Target model example are used, as follows:

	P50	P75	P90	P95
2021	45,00	40,08	35,66	33,00
2022	46,00	40,26	35,11	32,00
2023	48,00	41,84	36,33	33,00
2024	53,00	46,02	39,77	36,00
2025	57,00	49,61	42,99	39,00
2026	62,00	53,79	46,44	42,00
2027	65,00	56,38	48,66	44,00
2028	68,00	59,38	51,66	47,00
2029	72,00	62,56	54,10	49,00
2030	75,00	65,56	57,10	52,00
2031	77,00	67,56	59,10	54,00
2032	77,00	67,56	59,10	54,00
2033	78,00	65,69	54,66	48,00
2034	79,00	65,46	53,32	46,00
2035	81,00	67,87	56,10	49,00
2036	82,00	68,46	56,32	49,00
2037	82,00	66,00	51,65	43,00
2038	83,00	64,53	47,98	38,00
2039	84,00	60,61	39,65	27,00
2040	84,00	61,43	41,20	29,00
2041	84,00	63,07	44,32	33,00
2042	84,00	61,84	41,98	30,00
2043	83,00	57,56	34,76	21,00
2044	83,00	56,33	32,42	18,00
2045	83,00	53,46	26,98	11,00
2046	83,00	53,05	26,20	10,00
2047	83,00	52,22	24,64	8,00
2048	83,00	52,22	24,64	8,00
2049	84,00	52,81	24,86	8,00
2050	83,00	52,22	24,64	8,00

Table 5-8



Graph 5-3

5.3.2. Income

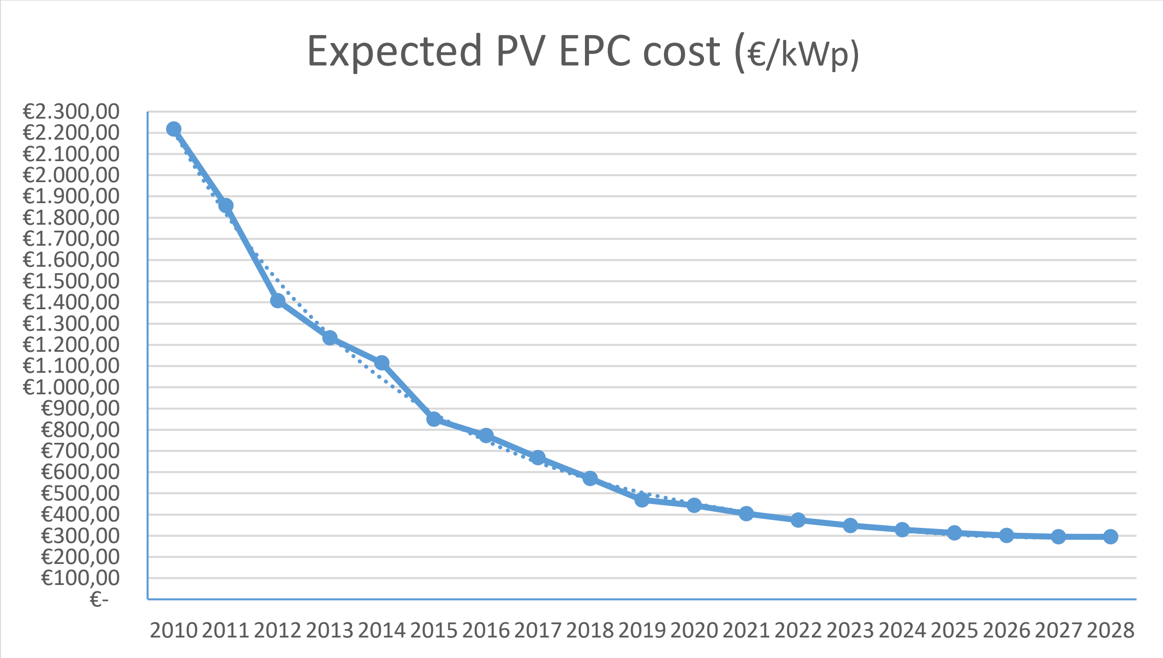
The income to be considered in the financial model is calculated with the same rationale as in the Onshore Wind case, where decision making is considered as per the P90 price trend scenarios.

Same as in the previous example, the produced energy for the 40MW PV station shall be:

40MWp*1600kWh/kWp=64.000MWh. For each year thereafter, the yield will drop 0,5% annually.

5.3.3. Capital Expenses

The EPC costs are expected to further reduce in the future, due to the rapid development of technology. In order to assess the construction costs in the future, IRENA power generation cost (IRENA, 2020) historical trend for PV (p.27) was examined, and by assuming a binomial trendline of historical EPC costs and dividing by 2,07 to include EUR/USD exchange rate and bring to current Greek prices (420€/kW in 2020) (Floudopoulos, 2021), future costs were estimated.



Graph 5-4

The trend shows that EPC costs are expected to reach 0,357€/kW in 2023, while the remaining development costs and construction costs remain at the same level, leading to a total cost of 0,50€/W with a total CAPEX of 20.000.000€ for the investment, which is a 20% reduction from 2020.

Similar to the previous examples, VAT is not used or calculated in the CAPEX cost.

5.3.4. Operational Expenses

The Operational expenses to be considered in the financial model, slightly differ from the ones of the previous example, due to their dependence from some income parameters.

PV station O&M prices are expected to be slightly more competitive than the ones introduced in the previous example, and reach 5.000€/MW/year

The remaining costs are calculated as described in the previous example.

Furthermore, due to the uncertainty of the power price, as in the Onshore wind example, a 5% price hedging is incorporated.

Overall OPEX cost reaches approx. 700.000€ for the first year of operation, which is once again higher than the one assumed in the FiP example, due to the 5% hedging cost.

5.3.5. Financial Parameters

The financial model was initially examined with exactly the same parameters as in the FiP example.

5.3.6. Financial Model

Once again the financial model was prepared as in the FiP example for a 20 year duration. Same as in the Onshore wind example, a lifetime extension to 25 years was also examined. The results of year one are presented below, and the full 20 year period rounded in k€, in the following table.

Year	1
Power price	2.313.384,07€
Income	704.271,98€
OPEX	69.401,52€
levies	1.539.711€
EBITDA	15.000.000€
Capital debt	750.000€
Capital repayment	555.000€
Interest	1.305.000€
Debt service	1.000.000€
Depreciation	-15.289€
EBT	-€
Income tax	-€
CFADS	1.539.711€
Net result	-15.289€
FCFE	234.711€

Table 5-9

	PV station within the Target model financial model																			
																				Sums in .000€
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Calendar Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Power price	0,036	0,040	0,043	0,046	0,049	0,052	0,054	0,057	0,059	0,059	0,055	0,053	0,056	0,056	0,052	0,048	0,040	0,041	0,044	0,042
Income	2.313	2.520	2.711	2.913	3.037	3.208	3.343	3.511	3.616	3.598	3.310	3.213	3.364	3.360	3.066	2.834	2.330	2.410	2.579	2.431
OPEX	704	716	728	740	748	758	767	777	784	784	769	764	774	775	758	745	716	721	732	724
levies	69	76	81	87	91	96	100	105	108	108	99	96	101	101	92	85	70	72	77	73
EBITDA	1.540	1.728	1.901	2.086	2.198	2.354	2.476	2.628	2.723	2.705	2.442	2.353	2.489	2.485	2.216	2.004	1.544	1.616	1.769	1.633
Capital debt	15.000	14.250	13.500	12.750	12.000	11.250	10.500	9.750	9.000	8.250	7.500	6.750	6.000	5.250	4.500	3.750	3.000	2.250	1.500	750
Capital repayment	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Interest	555	527	500	472	444	416	389	361	333	305	278	250	222	194	167	139	111	83	56	28
Debt service	1.305	1.277	1.250	1.222	1.194	1.166	1.139	1.111	1.083	1.055	1.028	1.000	972	944	917	889	861	833	806	778
Depreciation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
EBT	-15	201	402	614	754	938	1.088	1.267	1.390	1.400	1.165	1.103	1.267	1.291	1.050	865	433	533	713	606
Losses carried forward	-	-15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income tax	-	45	96	147	181	225	261	304	334	336	280	265	304	310	252	208	104	128	171	145
CFADS	1.540	1.684	1.805	1.938	2.017	2.129	2.215	2.324	2.389	2.369	2.163	2.088	2.185	2.175	1.964	1.796	1.440	1.488	1.598	1.488
Net result	-15	156	306	467	573	713	827	963	1.056	1.064	885	838	963	981	798	658	329	405	542	460
FCFE	235	406	556	717	823	963	1.077	1.213	1.306	1.314	1.135	1.088	1.213	1.231	1.048	908	579	655	792	710

Table 5-10

Once again the following modelling indicators were calculated:

LCOE@WACC	44,79 €
LCOE@10%	59,76 €
LCOE@7,5%	52,74 €
NPV equity	2.617.885,41 €
NPV project	5.721.218,06 €
equity IRR	14,58%
project IRR	7,45%

Table 5-11

From the calculated indicators we derive the following:

LCOE of the project of 44,79€/MWh is slightly below the average Power price of 49,12€/MWh, indicating an over remuneration.

Positive NPV for equity and overall project are also calculated, since equity and project IRRs are both above the estimated cost of equity and WACC respectively. The high equity IRR compared to the cost of equity is once again mainly due to the high equity gearing ratio.

5.3.7. Financing

The financing of the investment is again assessed as project finance in a non-recourse basis and DSCR and LLCR ratios were calculated, as follows.

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DSCR	1,18	1,32	1,44	1,59	1,69	1,83	1,95	2,09	2,21	2,25	2,10	2,09	2,25	2,30	2,14	2,02	1,67	1,79	1,98	1,91
LLCR	1,75	1,81	1,86	1,90	1,94	1,98	2,00	2,01	2,01	2,00	1,98	1,97	1,96	1,92	1,86	1,81	1,77	1,82	1,88	1,85

Table 5-12

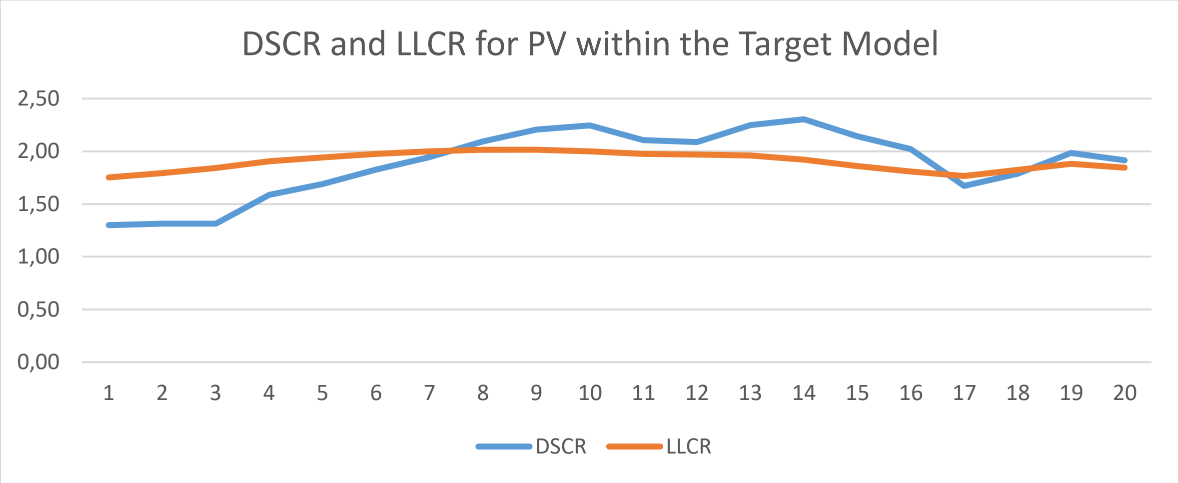
In comparison with the FiP example, DSCR follows the trend of the power price, while LLCR remains between 1,75 and 2,0, above the 1,3 acceptable threshold.

It should be noted that minor sculpturing at year 1 is necessary, due to the small DSCR, which gets corrected by deferring a payment of 120.000€ from year 1 to year 3.

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DSCR	1,30	1,31	1,31	1,59	1,69	1,83	1,95	2,09	2,21	2,25	2,10	2,09	2,25	2,30	2,14	2,02	1,67	1,79	1,98	1,91
LLCR	1,75	1,79	1,84	1,90	1,94	1,98	2,00	2,01	2,01	2,00	1,98	1,97	1,96	1,92	1,86	1,81	1,77	1,82	1,88	1,85

Table 5-13

And were again inserted in a diagram to indicate their trend in time.



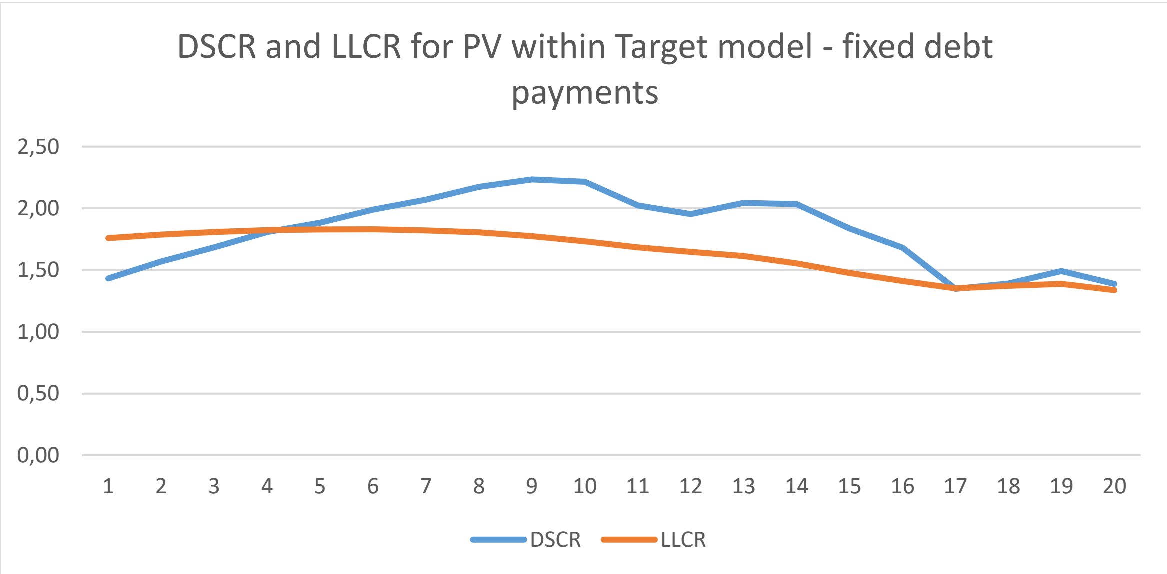
Graph 5-5

An additional investigation took place with fixed debt payments instead of fixed capital payments, as in the Onshore wind example.

Debt ratios remained above 1,30x in all cases, without the need of any sculpturing, as follows.

Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
DSCR	1,43	1,57	1,68	1,81	1,88	1,99	2,07	2,17	2,23	2,22	2,02	1,95	2,04	2,03	1,84	1,68	1,35	1,39	1,49	1,39
LLCR	1,76	1,79	1,81	1,82	1,83	1,83	1,82	1,81	1,77	1,73	1,68	1,65	1,61	1,55	1,48	1,41	1,35	1,37	1,39	1,34

Table 5-14



Graph 5-6

An examination also took place to identify how much the loan tenor could be decreased.

With fixed capital payments, tenor could be reduced to 15 years but required significant sculpturing for the first 3 years and repayment up to year 8, while for fixed debt payments, for the 15 year tenor, sculpturing was only needed for the first 2 years and repaid in years 3 and 4.

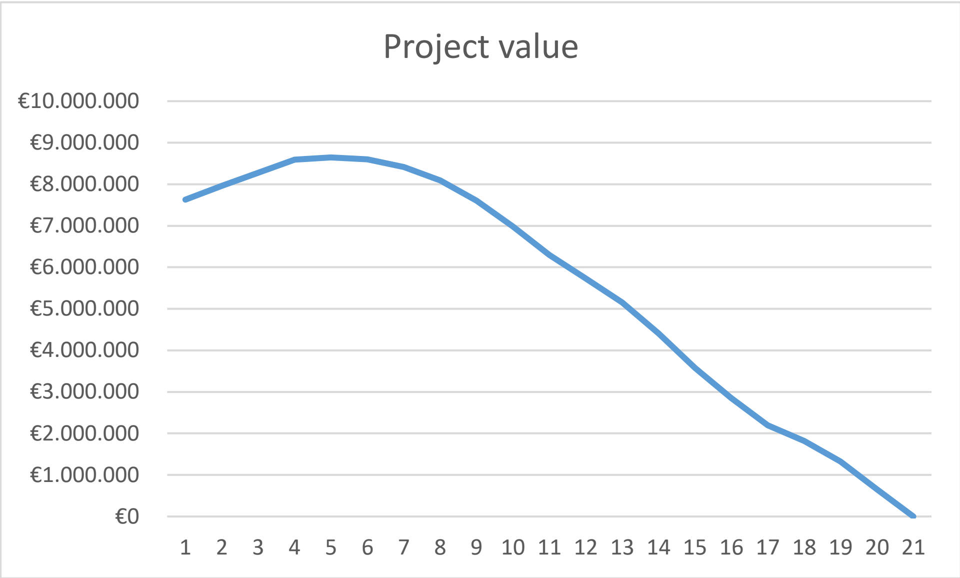
5.3.8. Valuation

The same valuation method of the discounted cash flow appraisal was followed, for the fixed capital repayment method

The values calculated at each year, are presented below.

Year	Valuation
1	7.629.869€
2	7.961.847€
3	8.275.529€
4	8.588.187€
5	8.644.470€
6	8.599.174€
7	8.410.583€
8	8.090.968€
9	7.605.868€
10	6.984.112€
11	6.298.635€
12	5.730.289€
13	5.157.615€
14	4.408.782€
15	3.574.697€
16	2.848.670€
17	2.197.450€
18	1.815.907€
19	1.324.597€
20	651.680€

Table 5-15



Graph 5-7

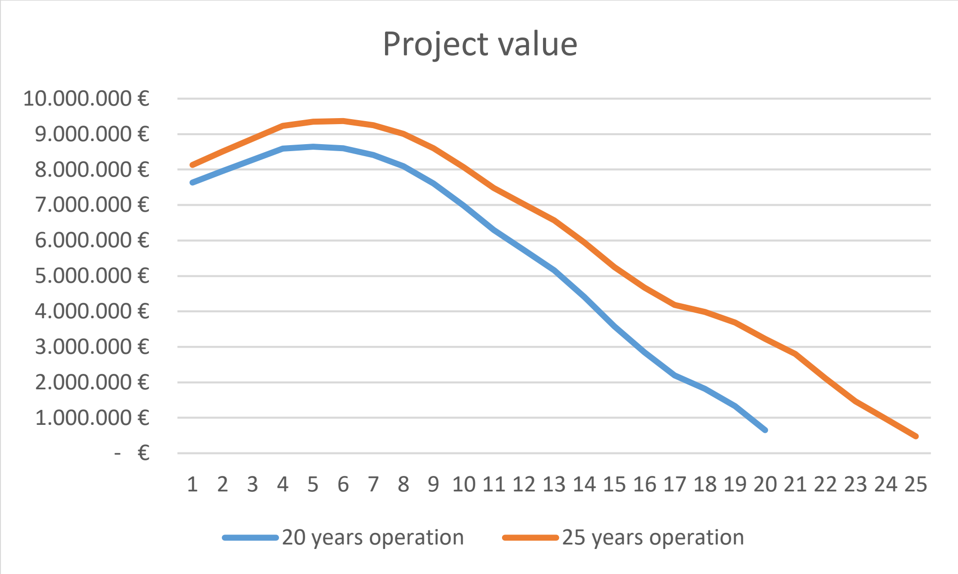
The valuation examination showed a slightly increasing value of the asset for the initial 5 years and a decreasing value after that, mainly due to the upwards trend of the expected power prices that result in increasing net result to equity more than the respective discount rate of equity cost.

This investment was also examined for a 25 year lifetime, which adds value of the income acquired after the 20th year, since by then debt is considered repaid. Depreciation could also be extended to 25 years rather than 20, nevertheless, for comparison reasons it was not changed.

The result is an additional value increasing each year up to the 21st, leading to the conclusion that extending the asset's life to 25 years is a preferable option.

	20 years operation	25 years operation	25 years vs 20 years operation
Year	**Valuation**	**Valuation**	**Difference**
1	7.629.869€	8.130.337€	500.468€
2	7.961.847€	8.507.357€	545.510€
3	8.275.529€	8.870.135€	594.606€
4	8.588.187€	9.236.308€	648.120€
5	8.644.470€	9.350.921€	706.451€
6	8.599.174€	9.369.206€	770.031€
7	8.410.583€	9.249.917€	839.334€
8	8.090.968€	9.005.843€	914.874€
9	7.605.868€	8.603.082€	997.213€
10	6.984.112€	8.071.074€	1.086.962€
11	6.298.635€	7.483.424€	1.184.789€
12	5.730.289€	7.021.709€	1.291.420€
13	5.157.615€	6.565.263€	1.407.648€
14	4.408.782€	5.943.118€	1.534.336€
15	3.574.697€	5.247.124€	1.672.426€
16	2.848.670€	4.671.615€	1.822.945€
17	2.197.450€	4.184.460€	1.987.010€
18	1.815.907€	3.981.747€	2.165.840€
19	1.324.597€	3.685.363€	2.360.766€
20	651.680€	3.224.915€	2.573.235€
21		2.804.826€	2.804.826€
22		2.115.549€	2.115.549€
23		1.463.789€	1.463.789€
24		974.141€	974.141€
25		476.491€	476.491€

Table 5-16



Graph 5-8

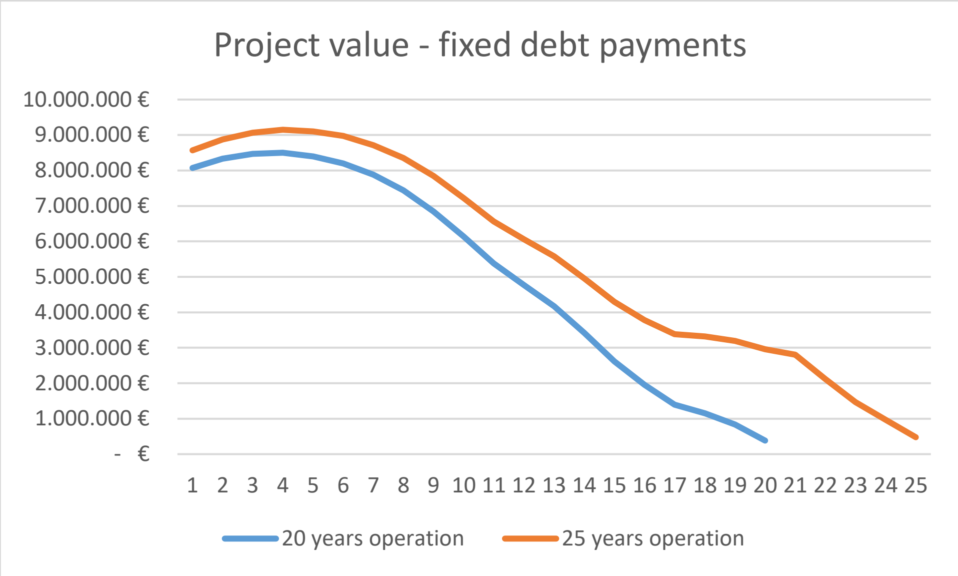
The valuation examination in year 1 shows a 53% gain on equity for the 20year example, which reaches 63% for the 25year example, which is significantly higher than the PV with a FiP's example of 17%.

The same example was examined for the two fixed debt payment scenarios, both for 20 and 25 years asset life, as follows.

	Fixed debt payments		
	20 years operation	25 years operation	25 years vs 20 years operation
Year	Valuation	Valuation	Difference
1	8.071.888 €	8.572.356 €	500.468 €
2	8.333.253 €	8.878.763 €	545.510 €
3	8.472.297 €	9.066.903 €	594.606 €
4	8.500.476 €	9.148.596 €	648.120 €
5	8.396.101 €	9.102.552 €	706.451 €
6	8.201.924 €	8.971.955 €	770.031 €
7	7.877.478 €	8.716.813 €	839.334 €
8	7.436.406 €	8.351.280 €	914.874 €
9	6.845.744 €	7.842.957 €	997.213 €
10	6.135.966 €	7.222.928 €	1.086.962 €
11	5.381.806 €	6.566.595 €	1.184.789 €
12	4.766.084 €	6.057.504 €	1.291.420 €
13	4.169.496 €	5.577.144 €	1.407.648 €
14	3.422.567 €	4.956.903 €	1.534.336 €
15	2.618.784 €	4.291.211 €	1.672.426 €
16	1.954.275 €	3.777.220 €	1.822.945 €

17	1.398.874 €	3.385.884 €	1.987.010 €
18	1.150.820 €	3.316.661 €	2.165.840 €
19	834.356 €	3.195.122 €	2.360.766 €
20	381.667 €	2.954.902 €	2.573.235 €
21		2.804.826 €	2.804.826 €
22		2.115.549 €	2.115.549 €
23		1.463.789 €	1.463.789 €
24		974.141 €	974.141 €
25		476.491 €	476.491 €

Table 5-17



Graph 5-9

In this case the valuation examination in year 1 shows a 61% gain on equity for the 20year example, which reaches 71% for the 25year example, even higher than the PV within the Target model with fixed capital payments.

6. Key Findings

The examination of the four cases resulted in a series of findings, which allow comparison among the cases and provide useful insights for the implementation of the Target Model.
A table was drafted which includes most significant metrics.

	Wind				
Remuneration	FiP	Target model	Target model	Target model	Target model
Asset life (years)	20	20	20	25	25
Debt repayment method	Fixed capital	Fixed capital	Fixed debt	Fixed capital	Fixed debt
LCOE@WACC	51,75€	47,81€	48,34€	43,32€	43,78€
Average Tariff	55,67€	49,12€	49,12€	49,12€	49,12€
NPV equity	4.486.701,88€	1.835.243,63€	2.683.800,50€	2.809.863,78€	3.658.420,65€
NPV project	10.087.928,46€	6.551.533,07€	6.839.590,27€	9.156.139,27€	9.444.196,47€
equity IRR	14,05%	11,05%	12,31%	11,78%	12,97%
project IRR	6,94%	6,15%	6,23%	6,65%	6,72%
1st year valuation gain on equity	40,79%	18,35%	26,84%	28,10%	36,58%
Sculpturing	No	Yes	Yes	Yes	Yes
	PV				
Remuneration	FiP	Target model	Target model	Target model	Target model
Asset life (years)	20	20	20	25	25
Debt repayment method	Fixed capital	Fixed capital	Fixed debt	Fixed capital	Fixed debt
LCOE@WACC	49,69€	44,80€	45,32€	43,10€	43,59€
Average Tariff	49,81€	49,12€	49,12€	49,12€	49,12€
NPV equity	1.031.848,64€	2.629.869,32€	3.071.887,96€	3.132.253,72€	3.572.355,59€
NPV project	3.463.644,14€	5.723.134,07€	5.821.761,72€	7.063.963,49€	7.157.446,88€
equity IRR	11,14%	14,64%	16,33%	15,09%	16,71%
project IRR	5,96%	7,45%	7,49%	7,87%	7,91%
1st year valuation gain on equity	16,51%	52,60%	61,44%	62,65%	71,45%
Sculpturing	No	Yes	No	Yes	No

6.1. Onshore wind farm with FiP

In this example equity IRR reaches 14%, which is ~50% higher than the 9% IRR sought, while project IRR also reaches almost 7%, once again slightly higher than 50% of the project's WACC of 4,36%.

The LCOE of 51,75€/MWh is lower than the FiP tariff assumed, of 55,67€/MWh, indicating a slight over-remuneration, while the financing of the project is achieved with initially high DSCR and LLCR indicators, above 1,50x with a positive trend.

The investment could also be easily financed with a 13 year loan tenor instead of the 20 year, with financing ratios above the 1,30x threshold.

If the investor were to sell the asset upon its successful construction and connection to the grid, he would make a 40,79% profit on the equity spent during development and construction, based on the valuation examination performed, while project valuation follows a downwards trend from the beginning.

6.2. Onshore wind farm within Target Model

Construction cost in the examined year (2023) is expected to be 10% reduced, compared to the one used in the FiP (2020) example. Moreover, in order to finance investments in the Target Model era, when electricity remuneration prices shall be uncertain and are expected to have high volatility, Lenders are expected to examine them with high exceedance probability price scenarios (P90 is expected to become the norm), while an additional electricity price hedging mechanism is also expected to be put in place, in order to mitigate income uncertainties.

This hedging mechanism was found to increase operational costs, which resulted in a lower IRR of 11-13% compared to the 14% of the previous example, regardless of the decrease of investment and maintenance costs, due to the evolution of technology.

LCOE reaches 47,81€/MWh to 48,34€/MWh, close to the average tariff of 49,12€/MWh which indicates fair remuneration of injected power.

The IRR drops even more to 10% or slightly lower, if the loan tenor is decreased to 15 years, while in that case heavy sculpturing of the repayment profile is necessary to maintain loan ratios above 1,30x.

A slight increase in IRR by 1% is noticed when extending the asset's useful life to 25 years instead of 20, which also brings LCOE down to 43,32€/MWh and 43,78€/MWh.

The DSCR was found to follow the trend of the power price, while the valuation calculation shows a 18,35% gain on equity for the 20year/fixed capital payments example, reaching a 36,58% for the 25year/fixed debt payments profile, similar to the Wind Farm with a FiP's example of 40%. This leads to the conclusion that investors in the Target model era are expected to negotiate fixed debt payment methods and extend the lifetimes of the assets at least to 25 years, in order to optimize use of equity, but are expected to enjoy similar IRRs. The latter is expected to further fuel investments in onshore wind in the future, regardless of the change of the remuneration mechanism.

Furthermore, the valuation examination revealed that the project's value is increased for the first few years and then turns to a downwards trend, due to the increase of the power price and net result to equity by a rate higher than the equity discount rate. This signifies an added value to the investor, if he holds on to the investment for some period.

6.3. PV station with FiP

The example calculated regarding PVs remunerated in the FiP framework, resulted in an IRR of 11,1%, which is slightly above the 9% initially modelled. Compared to Wind Farms' IRR of 14 %, it is clearly derived that the low development and construction risks of PVs compared to wind farms, as well as the low volatility of production, allows investors to seek lower IRRs and bid for lower prices, due to the reduced risk. This is also apparent from the LCOE of 49,69€/MWh which indicates fair remuneration at the 49,81€/MWh average FiP, compared to the slight over-remuneration identified for Wind farms.

In the PV example, as is the case of the Wind farm, high DSCRs and LLCRs were observed with a positive trend, while with a reduction of the loan tenor to 17 years, the relevant ratios remained above 1,30x.

The value estimation indicated that 16,51% is gained on equity invested, if the investor were to sell the asset on day one of operation commencement.

6.4. PV station within Target Model

Within the Target model, investments in PV stations seem to be more advantageous than Wind farms, due to the higher IRRs identified at the relevant example. The price drop of 2023 compared to 2020 was assessed at 20%, compared to the 10% expected for Onshore Wind farms.

PV investments offer an IRR of 14,64% for a 20 year investment with fixed capital payments that can extend to 16,71% with for a 25 year investment and fixed debt payments.

LCOE reaches 44,80€/MWh to 45,32€/MWh, lower than the average tariff of 49,12€/MWh which indicates a slight over remuneration of injected power. LCOE further drops to 43,10€/MWh to 43,59€/MWh for a 25 year lifetime assumption, while first year valuation gain on equity varies from 52,60% to 71,45%, which is almost doubled compared to the Onshore Wind farm example and significantly higher than the 16,51% identified in the PV FiP example. Same as in the Onshore wind within the Target model, the project's value is increased for the first few years and once again turns to a downwards trend, providing added value to an investor that holds on to the investment for some period.

Fixed debt repayment method requires no sculpturing to the repayment profile, while all repayment methods allow loan tenor decrease to 15 years with some sculpturing.

Once again 25year asset lifetime and fixed debt payment seems to be the optimal approach, while the high IRRs are expected to be attractive for future investments.

7. Conclusion

From the analysis of the examples assessed and the key findings identified, the following conclusions were reached, regarding financing of RES projects in Greece, as well as their valuation in time.

The construction prices of onshore wind farms are expected to continue their mild downwards trend in the future, while construction prices of PV stations will experience a steeper downwards trend. Due to this, PV stations will benefit from the transition to the Target model, compared to onshore wind farms, which are expected to have reduced returns compared to the previous years. Main cause of this seems to be the fact that low FiP prices had been reached at the recent RAE tenders for PV projects, but the free market will reduce technology specific competition and benefit low risk investments such as those.

The main driving factor for the returns of the investments will be the trend of the market's power price. The behavior of the market is a significant uncertainty parameter for Lenders, who are expected to follow high probability exceedance power price scenarios and also require hedging of the prices whenever possible and when the relevant market reaches adequate liquidity. This will cause additional operational expenses for the investments, but will allow the same high LTC ratios experienced nowadays, since debt ratios are expected to remain satisfactory. Loan tenors however will have to be extended from the average 8-12 years of the past to 20 years to allow for safe repayment of debt.

The value of RES assets in the past reached a peak in the first years of operation and immediately underwent a downwards trend. This seems to be changing for investments within the Target model which have an inclining valuation for the first 4-5 years before initiating a value reduction. This will discourage early sell-outs from the investors, who will hold on to the investments for a larger period of time.

The overall analysis identified that satisfactory IRRs will continue to fuel investments in the wind sector in the future but focus will switch to PV stations, which are expected to offer more generous returns.

This dissertation has examined the available parameters diligently, but was restricted by a number of limitations, which may have influenced its results. The Power price trend used was from one source only, due to lack of free publicly available studies. This means that any error of the said examination was also adopted within this analysis and could not have been mitigated by comparison with other sources. Furthermore, the Power price trend had a significant uncertainty for the future years, reaching a standard deviation of 55% of the power price in 2050. Nevertheless, the P90 probability exceedance scenario used is considered representative of the future power price trend. Moreover, since RES investments and particularly low risk investments such as PV stations were found to have very good returns, they are expected to eventually drive market prices down, as indicated in the scenario followed. One should not disregard the fact that the use of electric cars and replacement of fossil fuels is a price up-driving factor, but the European market coupling and the rapidly evolving RES technology will balance things.

Further research sectors were also identified through this examination. The approach followed could be reassessment once the Target model has been rendered fully operational, state incentives have been withdrawn from the RES investments, and the market has balanced. Moreover, the response of the Market to the implementation of the sale of electricity through bilateral PPAs could also be examined.

Finally, the results of this dissertation could be the point of initiation for further examinations in the RES sector, especially for Offshore wind farms that have not been thoroughly examined in the past, due to their limited global development and incomplete local legislative framework.

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