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Simulation of Wind Power Generation System and Clean Development Mechanism for Electrification in Nazareth Site

A Thesis submitted to the School of Graduate Studies of Addis Ababa
Institute of Technology in partial fulfillment of the Degree of
Masters of Science in Energy Technology

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Abstract

In this thesis, the wind speed data measured by the GTZ TERNA program is used to assess the energy output for a hypothetical 51 MW installed capacity wind farm at Nazareth site. Using the RETScreen model, the energy output of the wind farm is presented in terms of gross energy production, renewable energy delivered, specific yield and wind farm capacity factor. The energy output analysis is done using four wind energy conversion systems of rated capacity 600, 800, 1000 and 1500 kW. The RETScreen model is used to perform the financial feasibility analysis of the wind farm at this site, likewise the sensitivity and risk analyses are performed.

Furthermore, a Clean Development Mechanism (CDM) assessment is performed for this wind park. The net annual and total revenue generated from Certified Emission Reduction sales is calculated assuming Certified Emission Reduction prices of $6. The application of subsides on capital finance to the up-front and Clean Development Mechanism periodic cost are considered in order to evaluate the impacts of Certified Emission Reductions on project viability.

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Abbreviations

ALCS	Annual Life Cycle Saving
B-C	Benefit to Cost
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
dB	decibells
DNA	Designated National Authority
DOE	Designated Operational Entity
DSC	Debt Service Coverage Ratio
EB	Executive Board
EEPCO	Ethiopian Electric Power Corporation
EMI	Electromagnetic Interface
EPA	Environmental Protection Authority
ERPA	Emission Reduction Purchase Agreement
GHG	Greenhouse Gas
GWP	Global Warming Potential
HAWT	Horizontal Axis Wind Turbines
ICS	Interconnected Systems
IRR	Internal Rate of Return
JI	Joint Implementation
LI	Lahmeyer International
MVP	Monitoring Verification Protocol
MWh	Mega Watt hour
NCAR	National Center for Atmospheric Research
NCEP	National Centers for Environmental Prediction
NPV	Net Present Value

PCF	Prototype Carbon Fund
PDD	Project Design Document
PPA	Power Purchase Agreement
RE	Renewable Energy
RETScreen	Renewable Energy Technologies Screen
SPP	Simple Payback Period
T&D	Transmission & Distribution
TERNA	Technical Experts of Renewable Energy Applications
USD	US Dollar
UNFCCC	United Nations Framework Convention on Climate Change
VHF	Very High Frequency
WECS	Wind Energy Conversion Systems
YPCF	Year to Positive Cash Flow

Chapter 1

Introduction

As time elapses, it is found that earth is getting warmer and warmer due to the emission of greenhouse gases. The key greenhouse gas causing global warming is carbon dioxide (CO_2). Approximately 80% of all anthropogenic (human caused) CO_2 emissions currently come from combustion of fossil fuels. Some of the implications of global warming are: rise in global temperature, rise in sea level, food shortages and hunger. So there is a need to promote research and development, transfer and use of technologies and practices for environmentally sound energy systems. Wind energy conversion systems (WECS) are the best example for this.

Wind power may become a major source of renewable, climate-friendly energy in developing countries. The capital costs and the competitiveness of electricity generation alternatives will strongly shape investments in renewable energy technologies in developing countries over the coming decades. The income earned by selling GHG emissions reductions will increase the total income to an investor from a project and will improve the competitiveness of wind power against conventional power generators in an increasingly competitive market [3].

The energy production, life-cycle cost and GHG emissions reduction are evaluated by using the RETScreen International Wind Energy Project Model. Six worksheets are provided in the wind energy project workbook file. First the energy model and equipment data worksheets are completed. The cost analysis worksheet should then be completed, followed by the financial summary worksheet. Then by using the GHG analysis worksheet, the GHG mitigation potential of the project is estimated. Finally the sensitivity of important financial indicators in relation to key technical and financial parameters is estimated by the sensitivity worksheet. This process should be repeated several times in order to help optimize the design of wind energy project from an energy use and cost stand point.

CDM is one of the "flexibility mechanisms" that is defined in the Kyoto Protocol. The purpose of the CDM is to promote clean development in developing countries, i.e., the "non-Annex I" countries (countries that aren't listed in Annex I of the Framework

Convention). The CDM is one of the Protocol's "project-based" mechanisms; in that the CDM is designed to promote projects that reduce emissions. The CDM is based on the idea of emission reduction "production". These reductions are "produced" and then subtracted against a hypothetical "baseline" of emissions. CDM projects are "credited" against this baseline, in the sense that developing countries gain credit for producing these emission cuts.

1.1. Problem Statement

Currently the Ethiopian government is giving attention to power generation from wind energy. This is because the electricity demands in the country increased more than fourfold in 12 years, which means annual increase of 16%. In order to address this demand, the government has launched a universal electricity access program with the view to enhance the access to 50% by 2010. This requires considerable new generating capacity other than hydropower, such as wind power. This is because, even though Ethiopia has a large hydropower potential, planning and installation of hydropower takes a very long time. Depending on only one power resource has also a high risk, such as lack of rain fall and climate change. In order to maintain increased energy security, wind energy is combined with hydropower. In Ethiopia wind power is complimentary to hydropower, in that during rainy season the wind power is low, where as in the dry season the wind potential is high.

There are some wind power generation projects which have already been started and proceeding in good manner. The Ethiopian government is also planning to maximize the amount of energy that can be exploited from wind power in the future. All wind energy assessments and feasibility studies are currently done by foreigners. This makes initial costs of wind farms to be very high. This is because there is no skilled manpower in this area. In order to fill this gap our government is forced to carry out the whole process of the wind projects by foreign engineers. This trend is costing the government a large amount of money, which decelerates the expansion rate of wind farms in the country.

There is, therefore, a need to adapt the techniques for wind power generation processes to avoid the flow of foreign currency to outside and maximize social value of engineers.

The shortest and reliable way of adapting this technology is through RETScreen International Wind Energy Project Model software. This software is important and beneficiary because it makes the way to Clean Development Mechanism (CDM) easier. Using RETScreen software the tons of CO_2 saved by the wind farm can be calculated. This helps in calculating the amount of additional cash flow that can be generated from Certified Emission Reduction (CER) sales.

The reasons why there is a need to carryout CDM assessment for wind projects are:

- Credited emission reductions, i.e. credit for producing emission cuts.
- Revenue from CDM projects could turn a marginally viable project into a project with more attractive returns [8].
- Income from CDM would reduce the project's overall financial risk and, therefore, the project's cost of capital [8].
- Better technique, technologies and processes
- Additional foreign investment
- Cleaner and more sustainable development
- Reduce greenhouse gas emissions
- Increase in environmental awareness

1.2. Objectives

Generally the purpose of this thesis is to adapt the techniques by which wind energy projects are developed. That is to make evaluation on the energy production, life-cycle cost and greenhouse gas (GHG) emission reductions for the wind farm by using the RETScreen International Wind Energy Project Model. As part of this thesis work, CDM assessment of the wind farm will also be included.

The specific objectives of this thesis in brief are:

- To select a feasible site for wind energy production.
- To evaluate the energy production,
- To evaluate cost analysis,

- To evaluate financial analysis,
- To calculate greenhouse gas (GHG) emission reductions
- To evaluate sensitivity of important financial indicators
- To explore, in particular, those issues that are important in the assessment and development of a CDM project.
- To select the best baseline methodology for the selected site.
- Evaluation of parameters for economic viability and feasibility of programmatic CDM based wind energy project.

1.3. Approach

For this study a hypothetical wind farm of 51 MW capacity, to be installed in Nazareth, is assumed. In order to optimize the design of wind energy projects from energy use and cost stand point, it is essential to go for different scenarios. This helps in choosing the best scenario for the design of the wind project. Therefore, four scenarios are selected for the feasibility analysis of the wind project.

1. 85 turbines each with the following specifications:
    - Wind turbine rated power: 600 kW
    - Hub height: 46 m
    - Rotor diameter: 43 m
2. 64 turbines each with the following specifications:
    - Wind turbine rated power: 800 kW
    - Hub height: 50 m
    - Rotor diameter: 52 m
3. 51 turbines each with the following specifications;
    - Wind turbine rated power: 1000 kW
    - Hub height: 60 m
    - Rotor diameter: 54 m
4. 34 turbines each with the following specifications:
    - Wind turbine rated power: 1500 kW
    - Hub height: 61.5 m
    - Rotor diameter: 66 m

<u>Note</u>: The turbine selection is based on the most available type of turbines in the market, which are manufactured by most wind turbine enterprises. Indeed the local infrastructure limitations in transporting the Energy equipments to the site are also considered.

The estimation of wind energy production is done by RETScreen software using the average wind speed at hub height and the energy production curve of the wind turbine. The estimated energy production of each turbine type is compared and evaluated based on the unadjusted energy production, gross energy production, specific yield and wind plant capacity.

A detailed economical analysis is done using the RETScreen model. The economic analysis is done by keeping all values the same except those values which are related with development, engineering, renewable energy equipments, balance of plant, miscellaneous and operation and maintenance costs. The economic feasibility study is performed in terms of Internal Rate of Return (IRR), Net Present Value (NPV), Annual Life Cycle Saving (ALCS), Simple Payback Period (SPP), Benefit to Cost ratio (B-C) and Debt Service Coverage (DSC).

The CDM assessment is performed by taking a CERs price of 6 USD/CER. The application of subsides on capital finance to the up-front and CDM periodic costs are considered in order to evaluate the impacts of CERs on IRRs and NPV of all scenarios.

The RETScreen software is capable of performing a Sensitivity and Risk analysis of wind energy projects. A sensitivity range of 20%, threshold value of 15% IRR and a 10% level of risk value are the main assumptions that are taken for the sensitivity and risk analysis. Using these assumptions the parameters which have the greatest impact on the project IRR are revealed.

1.4. Structure of Thesis

The structure of the thesis starts with the introduction, problem statement, objectives and approach in **Chapter One**. **Chapter Two** reviews literature about wind resource assessment and data interpretation, wind power generation, development of wind farms, environmental impacts and finally the Clean Development Mechanism. **Chapter Three** presents the conditions and the wind resource potential of Nazareth site. **Chapter Four** shows the comparison of the estimated annual energy production using different wind energy conversion systems. The output energy will be presented in terms of the gross energy production, renewable energy delivered, specific yield and plant capacity factor. **Chapter Five** discusses the estimation of wind energy project costs in terms of the initial and annual costs. **Chapter Six** critically analyses the financial feasibility of all wind farm scenarios. The common financial feasibility indicators, such as Internal Rate of Return, Net Present Value, Benefit to Cost ratio, etc, are used in order to compare the result of the financial feasibility analysis. The GHG emission reduction potential of all wind farm scenarios including the Clean Development Mechanism assessment are presented in **Chapter Seven**. **Chapter Eigh**t presents the sensitivity and risk analysis of the best scenario selected for this site. Finally the conclusion and implications are given in **Chapter Nine**.

Chapter 2

Literature Review

2.1 Introduction

The power of the wind has served mankind from ancient times to sail boats, grind grain, pump water, and so on. In this modern world, it has again emerged as one of the friendliest sources of energy as it does not require any fuel to burn and hence does not produce any kind of pollution. These days, due to rapid technological development, availability of megawatt-size wind turbines, ease of installation and operation, lower maintenance costs, long project life and competitive cost of energy production, wind power projects being developed throughout the world [5].

Rehman [5] presented the energy and economical analysis of 30 MW installed capacity wind farms at five coastal locations, using the RETScreen model, in terms of unadjusted energy, gross energy, renewable energy delivered specific yield and plant capacity factor using wind machines of 600, 1000 and 1500 kW. The study concluded that except the two sites, viz. Yanbo and Dhahran, the remaining three sites were found not to be economically feasible for wind park development to generate electricity using any sizes of WECSs. Y.Himri et al. [6] utilized wind speed data over a period of 10 years from three stations in order to assess the energy output for a 30 MW installed capacity wind farm in terms of unadjusted energy, gross energy, renewable energy delivered specific yield and plant capacity factor using wind machines of 600, 1000 and 2000 kW. They used the RETScreen model to perform the economical feasibility of the wind farms at these locations. They concluded that the wind farm consisting of 30 wind turbines of 1 MW rated power each is more feasible for all sites than using other WECSs.

An accurate wind resource assessment is a primary and critical factor to be well understood for harnessing the power of the wind at any location. A wind speed measuring campaign is conducted by EEPCO in co-operation with GTZ TERNA. Of the evaluated sites, five measuring stations, viz. Ashegoda, Nazareth, Harena Tele, Gondar and Maymekden, offer sufficient wind energy potential with 5 to 8 m/s average wind speeds in 10 m above ground. A wind speed measurement at 40 m towers is carried out for the three best sites. After a 4 months measuring period and a correlation for the remaining time of the year with 10 m data an annual wind speeds of 6.86 m/s, 8.50m/s and 9.36 m/s are obtained at Harena, Ashegoda and Nazareth sites respectively. A conservative energy prediction for the reference turbine with 48 m rotor diameter and 800 kW installed generator power results in capacity factors between 23 and 35% [12].

Beside the energy output and economical analysis, LI [17] performed a Clean Development Mechanism (CDM) assessment for a wind power development at Ashegoda site. The assessment has shown that the Ashegoda Wind Park is suitable to be registered as a CDM activity. The best scenario, Scenario IV (Gamesa G58), results in an annual emission reduction potential of 4,058.42 tCO_2 per year the first crediting period and totaling 73,700.84 tCO_2. A potential additional cash flow of $442,205.1 is calculated considering the application of the CDM during the 20 years operational period. In another feasibility study done by LI [18] at Mesobo- Harena site, a total emission reduction potential and additional cash-flow of 30,463.94 tCO_2 and $182,783.6 are obtained for the scenario with the highest power generation (99.122 GWh) respectively. The study concluded that compared to similar sized wind park projects in other countries this amount is modest.

2.2 Site Descriptions

The proposed wind park is situated in the central part of Ethiopia, Nazareth. Nazareth is located in the Misraq Shewa zone of Oromia, at 8^0 33’ N, 39^0 16’ E/ 8.55^0 N, 39.27^0 E at an elevation of 1712 meters, 99 km southeast of Addis Ababa. The city sites between the base of an escarpment known as Gorodima to the west, and the Great Rift Valley to the east.

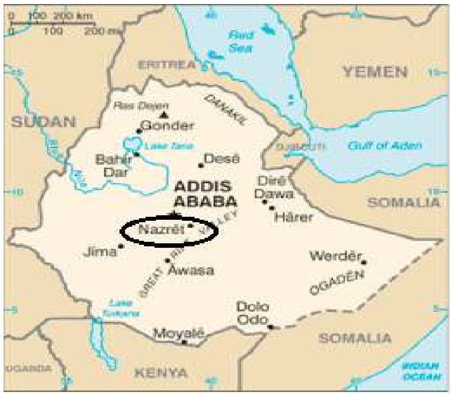


Fig. 2.1: Topographic map showing the location of Nazareth in Ethiopia.

2.3 Wind Resource

Two wind measuring towers were installed on top of a prominent hill west of the town (Gorodima, meaning in Oromifa ‘Red Hill’), for the proposed wind park site Nazareth. The first one is a 10 m and the other of 40m height. These towers are about 400m apart from each other (see Fig. 2.2).

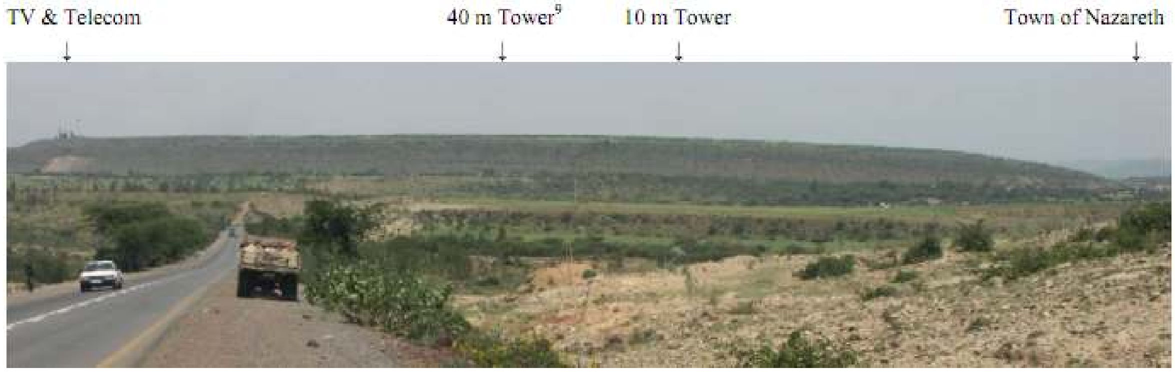


Fig. 2.2: Gorodima, Nazareth seen from the west [20]

The diurnal variation of wind speeds is not a decisive factor in the evaluation of wind projects connected to the interconnected systems (ICS): as long as the maximum power of the wind park is small compared to the grid load, all the wind power can be absorbed by the grid.

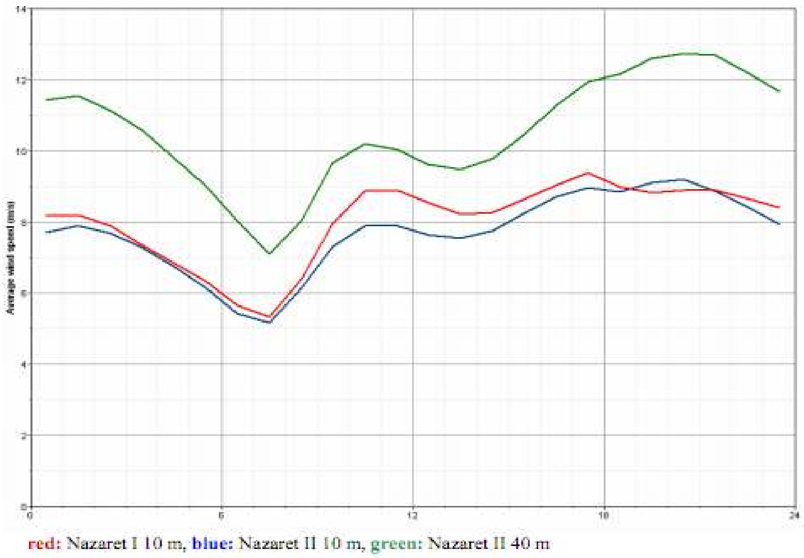


Fig. 2.3: Nazareth I and II- diurnal variation in m/s [12]

The diurnal variation during the common measuring period from October 2005 to January 2006 is given in Fig 2.3 [20, 20]. This figure also gives a first idea how different the actual wind speed in a wind park on the same hill can be: if there are already marked differences on a plateau in 400 m distance (see for example at 11:00 h, where the wind speeds difference between the two towers is nearly 1 m/s) – what might the different wind speeds be within a larger wind park stretching some km over the hill?

As can be observed from Fig 2.3, Nazareth has good diurnal variation and almost uniform wind speeds, apart from a small drop between 3:00 and 8:00 h, all the day.

Table 2.1: Nazareth ii 40m-monthly data 2005 (Feb.-sep: extrapolation to 40m)

Month	**Records**	**Recovery Rate (%)**	**Mean (m/s)**	**Min (m/s)**	**Max (m/s)**	**Std. Dev (m/s)**	**Weibull K**	**Weibull c (m/s)**
Jan	4,464	100	11.01	1.10	18.50	3.29	3.89	12.17
Feb	4,032	100	10.55	1.82	19.04	3.11	3.94	11.66
Mar	4,464	100	9.07	2.17	19.73	3.10	3.24	10.13
Apr	4,320	100	9.13	1.48	20.42	3.37	2.99	10.25
May	4,464	100	7.02	1.48	19.50	2.72	2.74	7.90
Jun	4,320	100	9.02	2.17	17.32	2.39	4.40	9.91
Jul	4,464	100	9.43	2.05	15.83	2.47	4.49	10.35
Aug	4,464	100	8.33	1.59	24.67	2.38	3.89	9.19
Sep	4,320	100	7.48	1.71	17.55	2.37	3.45	8.31
Oct	4,464	100	9.08	0.40	17.90	3.97	2.45	10.20
Nov	4,320	100	10.38	0.50	20.60	3.28	3.67	11.49
Dec	4,464	100	11.82	2.00	19.80	3.28	4.29	13.00
	52,560	100	**9.35**	0.4	24.67	3.30	3.14	10.46

The correlation of the February to September period gives, in combination with the measured data for the rest of year, an excellent annual wind speed of 9.35 m/s (see Table 2.1) [12, 20].

As can be seen from the frequency distribution in Fig 2.4 the Weibull shape parameter of k = 3.16 fits relatively well, thus, using Weibull analysis for greater hub height would yield good results [12, 21].

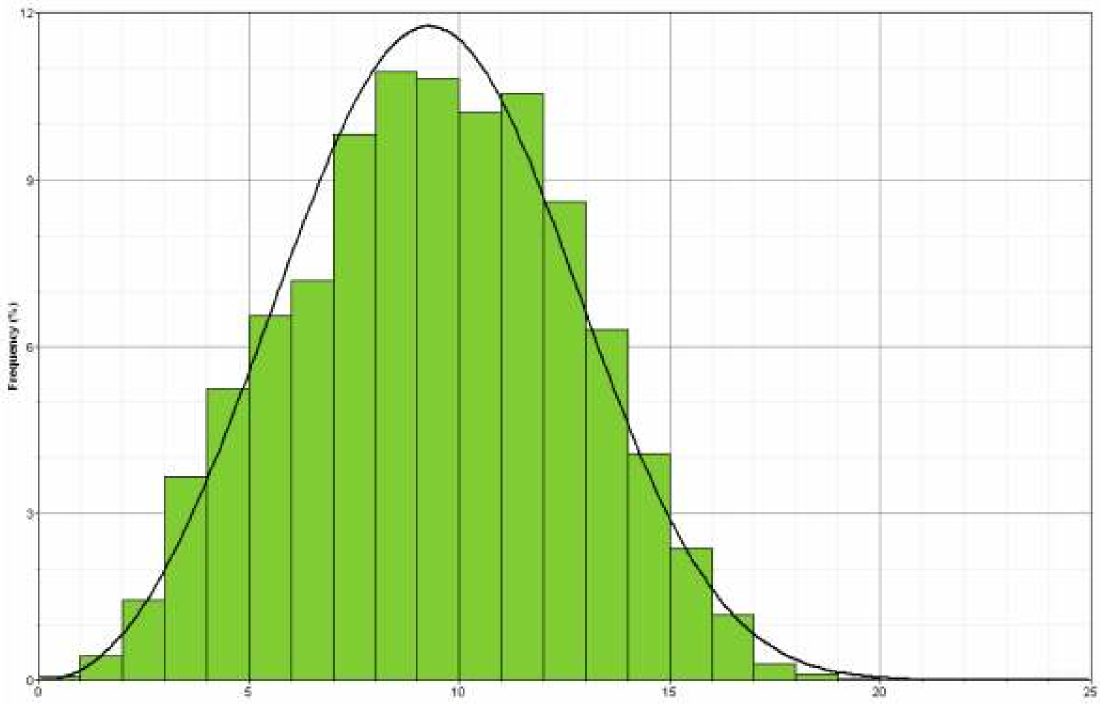


Fig. 2.4: Nazareth ii 40m-Frequency distribution at 40m height and best fit Weibull (February -September: extrapolation to 40m)

2.3.1 Turbulence Intensity

The turbulence intensity of a wind site is an indicator of the range of loads on the wind turbine induced by changing wind speed [12, 17]. High turbulence levels can cause additional strain on the rotor and drive train of a wind turbine, reduce the power output of and lead to a shorter life span of the equipment and/or higher service load.

Nazareth has low turbulences (10.2% or 16.5% for 40 and 10 m, respectively). Even though the turbulence intensity at 10 m is 16.5%, the actual operation of the wind turbine will not be affected. The turbulence intensity at hub height is below the maximum levels of the IEA recommendation in the whole wind speed range.

2.3.2. Wind Direction

A wind direction analysis is needed for the layout of the wind park. The knowledge of wind direction helps to know how many turbines can be placed at a given site. If only one predominant direction exists, the spacing of the turbines can be made relatively narrow thus saving space and, consequently, infrastructure costs.

Nazareth site has a single predominant wind direction, which is NE (see Fig. 2.5). The TERNA program concluded that Nazareth site has an extremely favorable wind direction condition: practically 2/3 of the available wind energy comes from one wind direction.

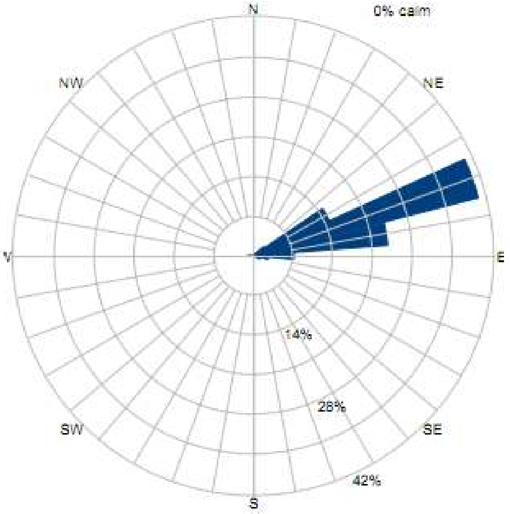


Fig. 2.5: Nazareth ii-Wind Direction [12, 20]

2.3.3 Correlation with Long-term Data

A correlation of on-site wind speed measurements is necessary when the wind speed data are to be used for a long-term energy estimation meant for an economic evaluation of a planned project.

Evaluating the synoptical wind speed data for the nearest grid point to Nazareth site gives a long-term annual wind speed variation according to Fig. 2.6.

The modeled 25-year average wind speed amounts to 2.16 m/s. The annual average for 2005 calculates to 2.01 m/s or 7% below the long-term average. From this, it is concluded that the TERNA measurements in 2005 have tendency of being below average.

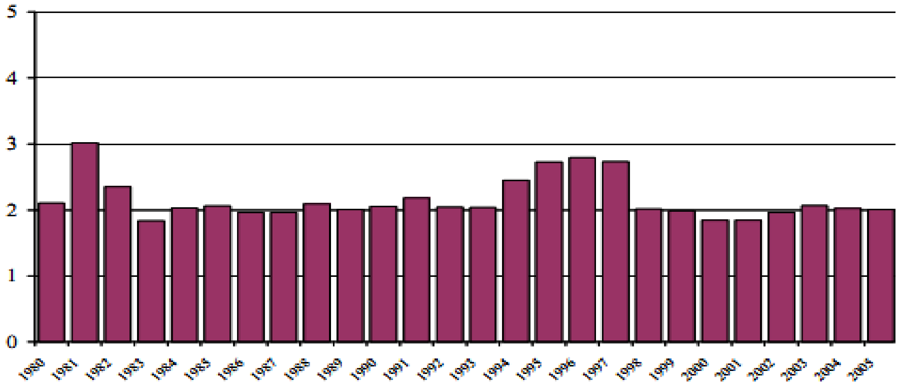


Fig. 2.6: NCEP/NCAR Wind Speed Data for Nazareth in m/s [12, 27]

With certain certainty, however, it is said that, judging from a comparison with the NCEP/NCAR data, the chance that measurement during an exceptionally windy year is relatively low [12, 27].

2.3.4 Ranking

Seven characteristics were taken from the measured wind regime in order to evaluate the status of the wind regime in the wind park. These are: wind speed, frequency distribution, wind shear, turbulence intensity, seasonal variation, diurnal variation and directional distribution. These categories have been weighted according to their relative influence on the operation of the wind park. With these criteria, Nazareth was selected as candidate site with the best wind regime of 85% in Ethiopia.

The white line (10 km) approximately indicates the direction of the ridge and is nearly perpendicular to the main wind direction.

Fig. 2.7: Nazareth-Candidate site with the best wind regime (85%) [12].

2.4 Clean Development Mechanism

The Clean Development Mechanism (CDM) is one of the three "flexibility" mechanisms defined in the Kyoto Protocol in 1997. It established to meet the climate convention objective of stabilizing greenhouse gas (GHG) concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. The remaining two flexible mechanisms, Emission Trading and Joint Implementation, are not applicable to developing countries. The CDM has two objectives; firs to assist non-Annex I parties, developing countries, in achieving sustainable development and in contributing the ultimate objective of the climate convention, and the second to assist Annex I parties, developed countries, with commitments under the protocol in reducing greenhouse gas emissions to comply with their reduction targets.

2.4.1 Certified Emission Reductions

The CDM allows an Annex I party to implement a project that reduces greenhouse gas emissions or, subject to constraints, removes greenhouse gases by carbon sequestration in the territory of a non-Annex I party. The resulting CERs can then be used by the Annex I Party to help its emission reduction target. The project can be initiated by a developing country also, in which case they need to find a buyer for CERs. This is termed as unilateral CDM [10].

2.4.2 Administration

The CDM is supervised by the Executive Board (EB), which itself operates under the authority of the Conference of Parties. [Conference of Parties is referred to the countries that are signatories to the climate convention]. The Executive Board is composed of 10 members, including one representative from each of the five official UN regions (Africa, Asia, Latin America and the Caribbean, Central Eastern Europe, and OECD), one from the small island developing states, and two each from Annex I and non-Annex I Parties.

The Executive Board accredits independent organizations-known as operational entities-that will validate proposed CDM projects, verify the resulting emission reductions, and certify those emission reductions as CERs. Another key task of the EB is the maintenance of a CDM registry, which will issue new CERs, manage an account for CERs levied for adaptation and administration expenses, and maintain a CERs account for each non-Annex I party hosting a CDM project [10].

2.4.3 Participation

In order to participate in CDM, the participating countries should have ratified the Kyoto Protocol and established the National CDM Authority in their countries. Annex I Parties need to meet additional requirements such as commitments for reductions under the protocol, national system for the estimation of greenhouse gases, annual inventory of GHGs, national registry and an accounting system for the sale and purchase of emission reductions [10].

2.4.4 Project Eligibility

The Kyoto Protocol stipulates several criteria that CDM projects must satisfy. Two critical criteria could be broadly classified as additionality and sustainable development.

i. Additionality

Article 12 of the Protocol states that projects must result in “reductions in emissions that are additional to any that would occur in the absence of the project activity” The CDM projects must lead to real, measurable, and long-term benefits related to the mitigation of climate change. The additional greenhouse gas reductions are calculated with reference to a defined baseline [26]. The Executive Board has developed an “additional tool” and has been used in many proposals for new baseline methodologies [10].

ii. Sustainable Development

The protocol specifies that the purpose of the CDM is to assist non-Annex I Parties in achieving sustainable development. There is no common guideline for the sustainable development criterion and it is up to the developing host countries to determine their own criteria and assessment process [26]. The EB only needs a certification by the host country that the project meets their sustainable development criteria [10, 9]. The criteria for sustainable development may be broadly categorized as [26, 13]:

- Social criteria. The project improves the quality of life, alleviates poverty, and improves equity.
- Economic criteria. The project provides financial returns to local entities, results in positive impact on balance of payments, and transfers new technology.
- Environmental criteria. The project reduces greenhouse gas emissions and the use of fossil fuels, conserves local resources, reduces pressure on the local environments, provides health and other environmental benefits, and meets energy and environmental policies.

2.4.5 Crediting Periods

Two alternative approaches to eligible crediting periods are identified in the Marrakesh Accords from November 2001 [8, 19].

i. A crediting period of maximum seven years which may be renewed no more than two times. It is necessary that, for each renewal, the CDM’s executive board is informed that the original baselines is still valid or has been updated; or
ii. A maximum of ten years with no option of renewal.

Self- evidently, the first alternative would be preferable for wind power projects because their project lifetimes often exceed ten years. Importantly, this alternative allows for updating of the data used in setting the baseline, but it apparently does not to allow for a change of the baseline approach itself. The need for updating the baseline and perhaps revising the baseline method is most pertinent for CDM projects with long lifetimes [8, 19].

2.4.6 Project Boundary and Emission Leakage

The project boundary or the monitoring domain should be defined in a way such that it covers all significant anthropogenic GHG emissions that are reasonably attributable to a CDM project. Emissions leakage is defined as the increase in emissions which occur outside the boundary of a project, and which is measurable and attributable to the CDM project. Leakage could reduce the amount of net emissions from CDM projects. Internationally, much attention is being paid to emissions leakage [8, 21].

2.4.7 Baselines for Wind Power Projects

The baseline for a CDM project is the scenario that reasonably represents the anthropogenic or human-induced GHG emissions that would occur in the absence of the CDM project. A baseline should cover emissions from all gases, sectors, and sources that exist within the project boundary. Emission from the base case and from a CDM project in the energy supply area may generally be conceived of as follow [8, 25]:

GHG emissions = Project *output * energy use/output * GHG emissions/energy use*

Two conceptually different notions or approaches are available for project developers: standardized and project-specific baselines. The first type of baseline makes it possible for multiple projects of the same type (e.g. renewable projects) implemented under similar conditions to use the same baseline. Standardized approaches may not be as accurate as project-specific baselines in calculating GHG reductions, at least at the level of individual CDM projects, and might for this reason be seen as less environmentally credible. On the other hand, standardized approaches lower the transaction costs and are therefore more likely to facilitate investments in CDM projects. The challenge is to strike the right balance between accuracy (environmental integrity) and the costs of developing (and monitoring) a baseline (transaction costs) [8, 27].

2.4.7.1 Internationally Approved Baseline Approaches

International regulation recently established under the UNFCCC suggests implicitly that project developers can chose between standardized and project-specific approaches when developing actual projects. Thus, according to the agreement at COP-7 in Marrakesh, morocco, in November 2001 [8, 30];

I. With respect to project-specific baselines it is pointed out that they should take "in to account relevant national and/ or sectoral policies and circumstances, such as sectoral reform initiatives, local fuel availability, power sector expansion plans, and the economic situation in the project sector"; whereas
II. With respect to standardized baselines, project developers can select from among three different approaches:
    a) "Existing actual or historical emissions, as applicable; or
    b) Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment; or
    c) The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 percent of their category."

Note: The RETScreen GHG Analysis worksheet can be used for each of these approaches.

The executive board (EB) approved three standardized baseline methodologies for renewable energy projects based on the above three approaches, which cover wind projects also. The approved methodologies are [10, 68]:

i. <u>Approved Baseline Methodology AM0005</u>: applies to small grid-connected zero-emissions renewable electricity generation. The approach refers to the criterion "emissions from a technology that represents an economically attractive course of action taking into account barriers to investment".
ii. <u>Approved Baseline Methodology AM00019</u>: applies to renewable energy projects replacing a part of the electricity production of one single fossil fuel fired power plant that stands alone or supplies to a grid. The approach refers to the criterion "existing actual or historical as applicable".

iii. Approved Consolidated Baseline Methodology ACM0002: applies to grid connected electricity generation from renewable sources. The approach refers to both the above criteria; "existing actual or historical emissions as applicable" and "emissions from a technology that represents an economically attractive course of action taking into account barriers to investment".

2.4.8 The CDM Project Cycle

There are four main phases or steps in the CDM project cycle: (1) project development or project design; (2) validation and registration; (3) implementation and monitoring; and (4) verification and certification. These steps are common to all CDM projects, although they may be simplified and fast-tracked in the case of small- scale projects [8, 21]. Different actors are involved at the various steps in the project cycle, see Fig.1.

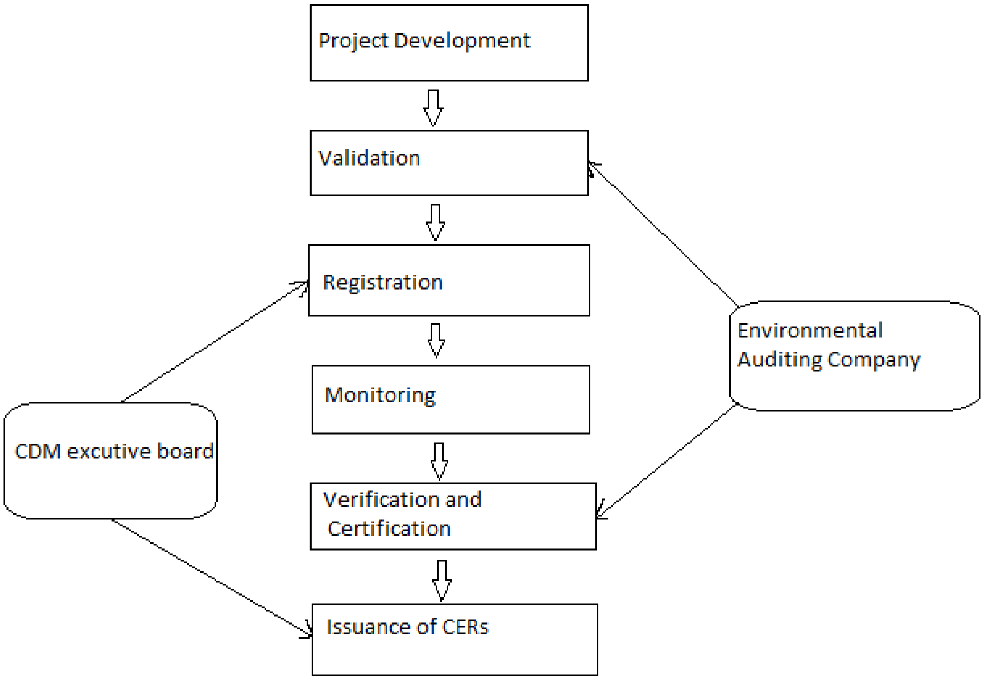


Fig 2.8: Steps in the CDM project cycle and actors involved

2.4.8.1 Project Development

Project screening is a useful exercise that at an early stage can help project developers, investors, and host countries to identify unpromising project candidates. Project participants shall include a monitoring and verification protocol [8, 22].

2.4.8.2 Validation and Registration

Validation refers to an independent evaluation and approval of the design of a CDM project, including the project baseline and the monitoring verification protocol (MVP), by a so-called designated operational entity before a project can be implemented. Registration is the formal acceptance by the CDM executive board of a validated project as a CDM project. Registration is a prerequisite for the verification, certification, and issuance of CERs related to a project [8, 22].

2.4.8.3 Monitoring

Monitoring is the systematic surveillance of the performance of the project by the implementers by measuring, evaluating and archiving of performance-related indicators. Monitoring will need to follow agreed and established rules and standards when they become available in the context of the Kyoto Protocol and the CDM. Specifically, monitoring will need to follow the steps, procedures and methods defined in the MVP developed for the project [8, 23].

2.4.8.4 Verification and Certification

Verification is the periodic independent review and *ex post* determination by an independent verifier of the monitored GHG reductions that have occurred as a result of the CDM project. Verification will be governed by the MVP or by a similar set of guidelines in accordance with national and international requirements. Certification is the written assurance by the accredited verifier that a CDM project achieved the GHG reductions ad verified. The certificate will likely state that the emission reductions achieved can be used to meet commitments under the Kyoto protocol; thus, the certificate will create "certified emission reductions" under article 12 of the Kyoto protocol [8, 23].

2.4.9 Project Design Document

The project design document (PDD) is a key and required document in the process of preparation and implementation of a CDM project. The content of a PDD are standardized and have been set by the executive board. Given that the CDM is an evolving process and the executive board is constantly making new decisions, it is possible that the EB may again modify the content of the PDD in the future. It is hence recommended to follow the meeting and decisions by the EB. The current contents of a PDD are as follow [10, 52]:

- Chapter A: General description of project activity
- Chapter B: Application of a baseline methodology
- Chapter C: Duration of the project activity/ crediting period
- Chapter D: Application of a monitoring methodology and plan
- Chapter E: Estimation of GHG emission by source
- Chapter F: Environmental impacts
- Chapter G: Stakeholders comments
- Annex 1: Contact information on project participants in the project activity
- Annex 2: Information regarding public funding
- Annex 3: Baseline information
- Annex 4: Monitoring plan

2.4.10 Financing CDM Projects

2.4.10.1 Carbon Markets

The CER market is one of the fragmented carbon markets. The global carbon market consists of diverse greenhouse gas reduction transactions and can be broadly classified as follow:

- Project-based or baseline and credit system. Emission reductions are credited and traded through a given project or activity. CDM and JI are examples of the project-based system where CERs and ERUs are generated respectively.
- Allowance markets or cap and trade system. Emission allowances are defined by regulations at the international, national, regional or firm level. Examples of allowance market include the emission trading under the Kyoto protocol (global), EU ETS (regional), the UK and the Danish trading systems (national), and BP and Shell internal trading (firm).

Various motivation of carbon buyers result in the differentiation of the carbon market. These are the following: i) immediate compliance in the national markets where buyers seek to comply with existing legislative obligations and constrains; ii) Kyoto pre-compliance where ;buyers expect the project to be registered under either JI or CDM; iii) voluntary compliance where buyers aim to use the emission reductions to meet part of their voluntary targets; and iv) retail schemes where buyers wish to be climate-neutral in order to demonstrate their social responsibility or promote particular brand (PCF, 2003).

The World Bank's PCF and the Dutch government's C-ERUPT are the current main buyers of CERs through direct purchase transactions.

2.4.10.2 CDM Project Viability

CDM projects produce both conventional project output and carbon benefits (CERs). The value of carbon benefits and its impact on project viability are influenced by several factors such as the amount of CERs generated by the project, the price of CERs and the transaction costs involved in securing CERs [26, 64].

i. Quantity of CERs

The amount of CERs by the project depends on the greenhouse gas displaced by the projects and the crediting period selected. Projects that capture methane and greenhouse gases other than CO2 produce more CERs since the global warming potential (GWP) of methane and other gases are several times higher than that of carbon dioxide. Projects with crediting period options 7 years with twice renewal can earn better amount of CERs than that of 10 years without renewal.

ii. Price of CERs

The price of CERs is determined in the carbon market. At present, the carbon market is a 'loose collection of diverse transactions' where emission reductions are exchanged. There are three main markets where greenhouse gas emission reductions are traded: project base or "baseline and credit" system; allowance market or "cap and trade" system and; voluntary market.

The pricing of CERs is highly speculative. The prototype carbon fund (PCF) considers several parameters in determining its price in the PCF's carbon purchase agreement. Moreover, certain project parameters command price premiums under the PCF program. These include: the existence of government guarantees, project generation of social benefits and the exclusion of preparation costs in the total project cost. In C-ERUPT program, processes are also differentiated according to technology type. In recent GHG market analysis, Natsource (2002) forecasts process for project-based emission reductions (both JI and CDM markets) to vary from USD 3 to 5 for the period of 2002-2005, USD 2.5 to 9.0 during 2005-2007, and USD 5 to 11 from 2008-2012 [26, 65].

iii. Transaction Costs

Transaction costs are those that arise from initiating and completing transactions to secure CERs. These consists of pre-operational costs (or upfront costs), implementation costs (i.e. costs spread out over the entire crediting period), and trading costs. Pre-operational costs include direct expenses for search, negotiation, validation and approval. Implementation costs are those incurred for monitoring, certification and enforcement while trading costs are those incurred in trading CERs such as brokerage and costs to hold an account in national registry.

Chapter 3

Wind Energy Production Estimation

3.1 RETScreen Model Basics

The RETScreen International wind energy project model can be used world-wide to evaluate the energy production, life cycle costs and greenhouse gas emissions reduction for central-grid, isolated-grid and off-grid wind energy projects, ranging in size from large-scale multi-turbine wind farms to small-scale single-turbine wind-diesel hybrid systems.

There are five steps of standard analyses that have to be followed to make a decision. First, the energy model and equipment data worksheets must be completed. The cost analysis worksheet should then be completed, followed by the financial summary worksheet. The third and fifth steps, i.e. GHG analysis and sensitivity worksheets respectively, are optional analysis. Each worksheet is completed row by row from top to bottom by entering values in shaded cells. The design of wind projects can be optimized from energy use and cost standpoint just by repeating the above steps several times.

The model uses four different types of cell color coding for input and output cells. These are white, yellow, blue and grey cells. The white cells are used just to show the results calculated by the model, which are the output cells. Except the white one the other three cells are user input. The yellow cells are required to run the model. The blue cells are required to run both the model and the available online databases. The grey cells are required only for reference purposes not to run the model.

3.2 Energy Model Input Parameters

The energy model worksheet calculates the annual energy production for a wind energy project based upon local site conditions and system characteristics. The model presents the energy output of the wind farm in terms of unadjusted energy production, gross energy production, specific yield, wind plant capacity and renewable energy delivered. These terms are basic for the comparison of different technologies. The model input parameters are categorized into the following classes.

3.2.1 Site Conditions

The site conditions associated with estimating the annual energy production of a wind energy project are: wind data source, nearest location for weather data, annual average wind speed, and height of wind measurement, wind shear exponent, average atmospheric pressure, and annual average temperature. These site conditions are discussed in brief as follows.

3.2.1.1 Wind Data Source

There are two sources for the wind data. For this, the worksheet contains two options in the drop-down list which are: wind speed and wind power density. Here wind speed is selected as the wind data source. When the wind speed is selected, the model displays the annual average wind speed cell. Then the annual average wind speeds for a given height are entered.

3.2.1.2 Annual Average Wind Speed

The annual average wind speed values are entered into the input worksheet cells. The annual average wind speed is used to calculate the average wind speed at the hub height of the wind turbine. As explained earlier the annual average wind speed for Nazareth site is 9.34 m/s.

RETScreen Online Weather Databases can be used to get maps with estimated wind speed data for a region, based on measured data for specific sites. But these data are for locations that have usually not been identified and picked for the optimal wind power potential. Wind surveying in the vicinity of the weather station would lead to a site with a better average wind speed than the value provided in the online weather database. Therefore it is recommended to use project site data, when available, rather than the data provided in the RETScreen Online Weather Database.

3.2.1.3 Height of Wind Measurement

This is the height from the ground at which the annual average wind speed is measured. For most stations the standard height for wind measurement is at 10 meter. Potential good wind sites should have average wind speeds of at least 5 m/s at 10 m. For this site the height of wind measurement is 40 m.

3.2.1.4 Wind Shear Exponent

Wind shear exponent is a dimensionless number expressing the rate at which the wind speed varies with the height above the ground. Its value ranges from 0.10 to 0.40. The low end of the range corresponds to a smooth terrain (e.g. sea, sand and snow from 0.10 to 0.13). The high end of the range corresponds to a project in urban area. A value of 0.14 is a good first approximation when the site characteristics are yet to be determined [1, 12].

Table 3.1: Surface roughness for different terrain description [12]

Terrain Description	**Surface Roughness [m]**
Very smooth, ice of mud	0.00001
Calm open sea	0.0002
Blown sea	0.0005
Snow surface	0.003
Lawn grass	0.008
Rough pasture	0.01
Follow field	0.03
Crops	0.05
Few trees	0.10
Many trees, few buildings	0.25
Forest and woodlands	0.50
Suburbs	1.50
Centers of cities with tall buildings	3.00

Assuming neutral atmospheric stability conditions, i.e. that the ground surface neither heated nor cooled compared to the air temperature, wind velocity at height z above ground level is given by [2]:

$$V = V_{ref} \frac{\ln(Z/Z_o)}{\ln(Z_{ref}/Z_o)} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots. (3.1)$$

where V_{ref} reference velocity, i.e. a wind velocity at height z_{ref}, z height above ground level for the desired velocity V, z_o surface roughness length of the site, z_{ref} reference height

$$\frac{V}{V_{ref}} = \left(\frac{Z}{Z_{ref}}\right)^{\alpha} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (3.2)$$

where α = wind shear exponent

For the Nazareth site, the wind speed measurement was taken from two tower heights, at 10 and 40 m above ground level. So it is possible to calculate the wind shear exponent by taking the 10 m height as the reference height. The respective velocities for the two heights were measured to be 6.96 and 9.35 m/s, respectively. Using equation (3.2) the wind shear exponent calculated as 0.213.

3.2.1.5 Average Atmospheric Pressure and Annual Average Temperature

The power available from the wind depends upon the average atmospheric pressure on the site. This value is used to calculate the pressure coefficient adjustment. The average atmospheric pressure is inversely proportional to the altitude. For Nazareth the average atmospheric pressure is 81.4 kPa.

The power available from the wind depends upon the annual average temperature. This value is used to calculate the temperature coefficient adjustment. The greater the temperature, the lower the air density and therefore, the lower the power available from the wind [1, 13]. The annual average temperature typically ranges from -20 to 30^{o}C, depending upon the location, the temperature at standard conditions is 15^{o}C. For Nazareth the annual average temperature is 19.3^{0}C.

For those sites which are recognized by the software, these values can be obtained and directly pasted into the cell by using the RETScreen Online Weather Database.

3.2.1.6 Shape Factor

The shape factor is a characteristic of the Weibull distribution which determines the uniformity of the wind. Uniformity of wind at a site increases with shape factor. For a given average wind speed, a lower shape factor indicates a relatively wide distribution of wind speeds around the average while a higher shape factor indicates a relatively narrow distribution of wind speeds around the average. The shape factor is used to calculate the energy curve data. As stated in Chapter 2, the Weibull distribution for Nazareth site 3.14.

Note: The characteristics of wind turbines can be pasted from the RETScreen product database.

3.2.2 Wind Turbine Characteristics

The wind turbine characteristics include: wind turbine rated power, hub height, rotor diameter, swept area and shape factor. Table 3.2 summarizes the characteristics of the selected turbines in this study.

Table 3.2: The characteristics of the selected Turbines for the feasibility study

No	Rated power [kW]	Number of Turbines	Hub height [m]	Rotor diameter [m]	Swept area [m^2]
1	600	85	46	43	1,452
2	800	64	50	52	2,124
3	1000	51	60	54	2,290
4	1500	34	65	66	3,421

3.2.3 Power Curve Data

Wind turbine power curve data is the instantaneous energy (i.e. power) delivered by the wind turbine measured over its operating range of wind speeds at hub height. This performance characteristic is usually provided by the wind turbine manufacturer.

For each of the selected Wind Energy Conversion Systems (WECSs), the power curve data were calculated and inserted in to the software. The power curve is given by [27]:

$$P_V = P_R \left[\frac{V^n - {V_I}^n}{{V_R}^n - {V_I}^n}\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.. (3.3)$$

where V_I = cut-in velocity, V_R = rated velocity, V = velocity, P_R = rated power, P_V = power at V and n ideal velocity power proportionality.

Here, the cut-in and rated velocities are taken to be 3 and 14 m/s, respectively, whereas; the cut-out velocity is taken as 25 m/s. in that until the wind speed gets in to its cut-in there will not be any power generation. The turbine starts generating energy when the wind speed gets 3 m/s. then there will be an increase in power generation up to the rated velocity, i.e. 14 m/s. Power production between the rated and the cut-out velocity is constant. When the wind speed exceeds its cut-out value, there is no power generation as the system is shut down. This helps in protecting the rotors and drive trains from damage due to excessive loading.

For 600 kW turbines:

$$P_V = P_R \left[\frac{V^n - {V_I}^n}{{V_R}^n - {V_I}^n} \right] = 600 \left[\frac{V^n - 3^3}{14^3 - 3^3} \right]$$

By substituting the values of velocities from 1 up to 25 m/s, the corresponding power can be obtained. The same procedure is applied for the calculation of the power outputs for the other turbines also. The power output data of all scenarios is summarized in Table 3.3.

The wind turbine power and energy curve graph provides a representation of the power and energy delivered by the wind turbine measured over a range of wind speeds. The graph is based on the values from the power curve data (see fig 3.1). Here the power and energy curve graph is presented only for the 1500 kW turbine size; see Annex A-2 for the remaining wind turbine sizes.

Table 3.3: Wind turbine power curve data for all wind farm scenarios

Wind Turbine Sizes [kW] (Scenarios)							
600		**800**		**1000**		**1500**	
Velocity [m/s]	Power [kW]	Velocity [m/s]	Power [kW]	Velocity [m/s]	Power [kW]	Velocity [m/s]	Power [kW]
0	0.0	0	0.0	0	0.0	0	0.0
1	0.0	1	0.0	1	0.0	1	0.0
2	0.0	2	0.0	2	0.0	2	0.0
3	0.0	3	0.0	3	0.0	3	0.0
4	8.17	4	10.89	4	13.62	4	20.40
5	21.64	5	28.86	5	36.07	5	54.10
6	41.74	6	55.65	6	69.56	6	104.30
7	69.783	7	93.04	7	116.30	7	174.50
8	107.1	8	142.80	8	178.51	8	267.80
9	155.024	9	206.70	9	258.37	9	387.60
10	214.87	10	286.50	10	358.12	10	537.20
11	287.96	11	383.95	11	479.94	11	719.90
12	375.63	12	500.85	12	626.06	12	939.10
13	479.21	13	638.94	13	798.68	13	1,198.0
14	600.0	14	800.0	14	1,000.0	14	1,500.0
15	600.0	15	800.0	15	1,000.0	15	1,500.0
16	600.0	16	800.0	16	1,000.0	16	1,500.0
17	600.0	17	800.0	17	1,000.0	17	1,500.0
18	600.0	18	800.0	18	1,000.0	18	1,500.0
19	600.0	19	800.0	19	1,000.0	19	1,500.0
20	600.0	20	800.0	20	1,000.0	20	1,500.0

21	600.0	21	800.0	21	1,000.0	21	1,500.0
22	600.0	22	800.0	22	1,000.0	22	1,500.0
23	600.0	23	800.0	23	1,000.0	23	1,500.0
24	600.0	24	800.0	24	1,000.0	24	1,500.0
25	600.0	25	800.0	25	1,000.0	25	1,500.0

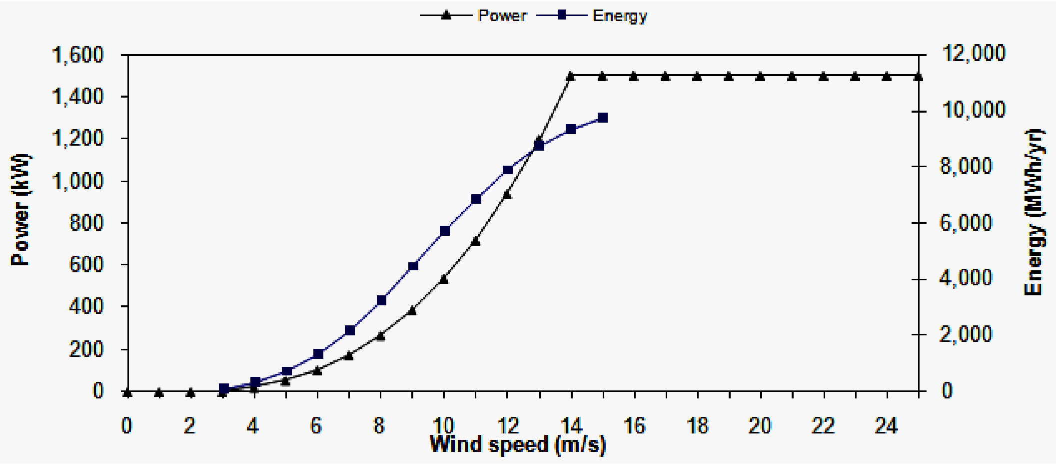


Fig 3.1: The Power and Energy Curve of 1500 kW Turbine size, from RETScreen model

3.2.4 System Characteristics

The system characteristics associated with estimating the annual energy production of a wind energy project includes: grid type, number of turbines and losses namely: array losses, airfoil soiling losses, other downtime losses and miscellaneous losses. These system characteristics are detailed below.

3.2.4.1 Grid Type

RETScreen wind energy project model contain three types of grid systems in its drop-down list. These are ‘Central-grid,’ ‘Isolated-grid’ and ‘Off-grid systems.’ The selection of these systems depends on the amount of energy produced by the wind project. It is quite obvious that this project is central-grid one, because the amount of energy produced from this wind project is large scale. For central-grid systems, the model assumes that all the energy produced by the wind project will be absorbed by the grid, i.e. that the grid load will always be higher than the capacity provided by the wind project.

3.2.4.2 Number of Turbines

The desired number of wind turbines depends on the rated capacity of the selected turbine (see Table 3.2). This item is used to calculate the total unadjusted energy production and the wind plant capacity. A large number of smaller turbines have the advantage of reducing the fluctuations in the total wind energy project output. On the other hand, the cost of large machines may be lower on a per kW basis [1, 14].

3.2.4.3 Losses

Losses are found on the whole energetic transformation chain from the rotor (kinetic energy) to the substation (electrical energy). The main losses which are significant includes: array losses, airfoil losses, other downtime losses and miscellaneous losses. The various forms of losses are detailed in Table 3.4.

Table 3.4: The assumed values of losses in the energy production

No	**Losses**	**Losses value [%]**
1	Array losses	3.0
2	Airfoil soiling losses	2.0
3	Other downtime losses	2.0
4	Miscellaneous losses	2.0
	Total losses	**9.0**

- Array Losses

Array losses are caused by the interaction of the wind turbines with each other through their wakes. Turbines in the “shadow” of others do not “see” as much wind as the front ones and energy production is decreased as a result. Array losses depend on the turbine spacing, orientation, site characteristics and topography.

Typical values for a well designed wind farm ranges from 0 to 20% of ”Gross energy production”. The lower end of the range corresponds to small clusters of well spaced turbines while the higher end of the range corresponds to a closely packed wind farm with a weak dominant wind. Array losses for a single turbine installation are 0% while a well designed cluster of less than 8 to 10 turbines should keep array losses below 5% [1, 17]. For this project the array losses is assumed to be 3%, for the reason that there is no space constraint.

- Airfoil Soiling Losses

Airfoil soiling losses are caused by soiling of the blades from such things as bugs build-up. Accumulation of bugs affects the aerodynamic performance of the blades. It can be improved by washing the blades regularly. Airfoil losses are used as input in the model to calculate the losses coefficient. Typical values range from 1to 10% of ”Gross energy production” [1, 17].

- Other Downtime Losses

Other downtime losses are result of scheduled maintenance, wind turbine failures, station outage and utility outage. Typical values range from 2 to 7% of “Gross energy production”. In the case of wind turbines installed in extreme environments (arctic climate, weak grid, etc.), losses are more likely to be toward the higher end of the range. Other downtime losses are used as input in the model to calculate the losses coefficient [1, 17].

- Miscellaneous Losses

Miscellaneous losses represent losses of energy production due to starts and stops, off-yaw operation, high wind and cut-outs from wind gusts. They also include any parasitic power requirements and any transmission losses from the wind energy project site to the point where the project connects to the local distribution grid. Miscellaneous losses are used as input in the model to calculate the losses coefficient. Typical values range from 2 to 6% of ”Gross energy production” [1, 18].

3.3 Annual Energy Production

In order to assess the energy output for the 51 MW installed capacity wind farm using different WECS, annual energy production is taken as the first criteria before the economic analysis is evaluated. The model calculates and displays those values which are basic in determining the annual energy production of the wind project. The calculated items are ***gross energy production**, **specific yield**, **wind plant capacity factor*** and the ***renewable energy delivered***. These items are very important in comparing the performance of different wind energy conversion equipments for a particular site. Detailed explanations and results for these items are given below.

3.3.1 Gross Energy Production and Renewable Energy Delivered

Gross energy production is the total annual energy produced by the wind energy equipment, before any losses, at the wind speed, atmospheric pressure and temperature conditions at the site [1, 19]. Gross energy production E_G is calculated through [2, 16]:

$$E_G = E_U * C_H * C_T \quad (3.4)$$

where E_U is the unadjusted energy production, it is the energy produced by the turbine at standard conditions of temperature and atmospheric pressure. Analytically given by:

$$E_U = P_V * f(V_{ave}) \quad (3.5)$$

Where V_{ave} is average wind speed at hub height and C_H and C_T are the pressure and temperature adjustment coefficients. Pressure adjustment coefficient is proportional to the average atmospheric pressure at the site, which in turn depends primarily on site elevation. Temperature adjustment coefficient is inversely proportional to the average temperature at the site. C_H and C_T are given by [2, 16] and defined as:

$$C_H = \frac{P}{P_0} \quad (3.6)$$

$$C_T = \frac{T_0}{T} \quad (3.7)$$

where P is the annual average atmospheric pressure at the site, 81.4 kPa for Nazareth, P_0 is the standard atmospheric pressure of 101.235 kPa, T is the annual average absolute temperature at the site, 292.62 K for Nazareth, and T_0 is the standard absolute temperature of 288.1 K.

The quantity of energy that can be captured by a wind turbine depends up on the power versus wind speed characteristics of the turbine and the wind-speed distribution at the turbine site [28]. The energy corresponding to a certain wind velocity v is the product of the power developed by the turbine at v and the time for which this velocity v prevails at the site.

So along with the power characteristics of the turbine, the probability density corresponding to different wind speeds also comes in to energy calculations. The probability density function ***f(v)*** indicates the fraction of time (or probability) for which the wind is at a given velocity. And it is given by:

$$f(V) = \frac{K}{C}\left[\frac{V}{C}\right]^{K-1} e^{-\left(V/C\right)^{K}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3.8)$$

Where k and c are Weibull shape factor and scale factor respectively. The values of average shape factor and scale factor, for Nazareth site, are given in table 2.1. The resulted probability density curve corresponding to different wind speeds is given below.

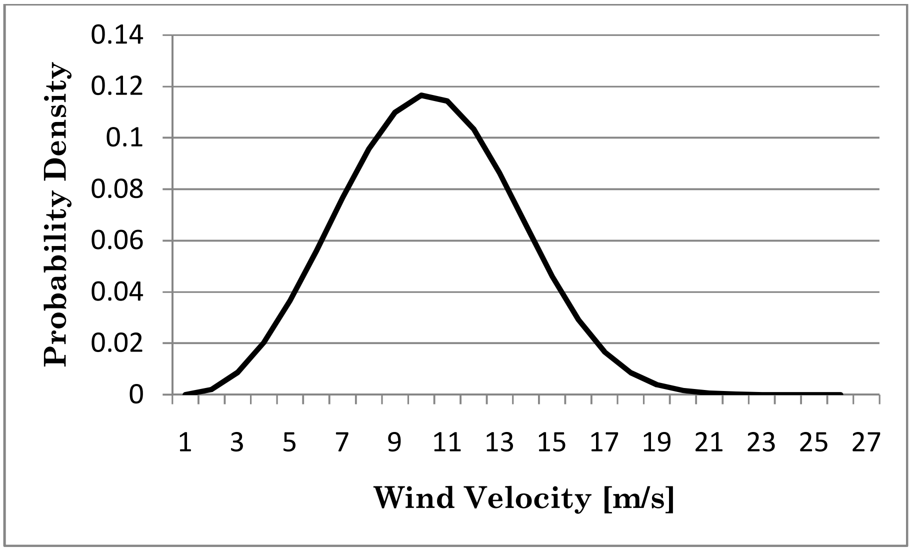


Fig 3.2: Weibull Probability Density Function for Nazareth site

The Energy capture curve is obtained by multiplying each points of the Power curve by the corresponding values of probability density curve. Analytically each point of the energy curve is calculated as:

$$E_V = P_V * f(V) \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (3.9)$$

The energy capture curve for the best scenario, 1500 kW turbine size, is given as follow.

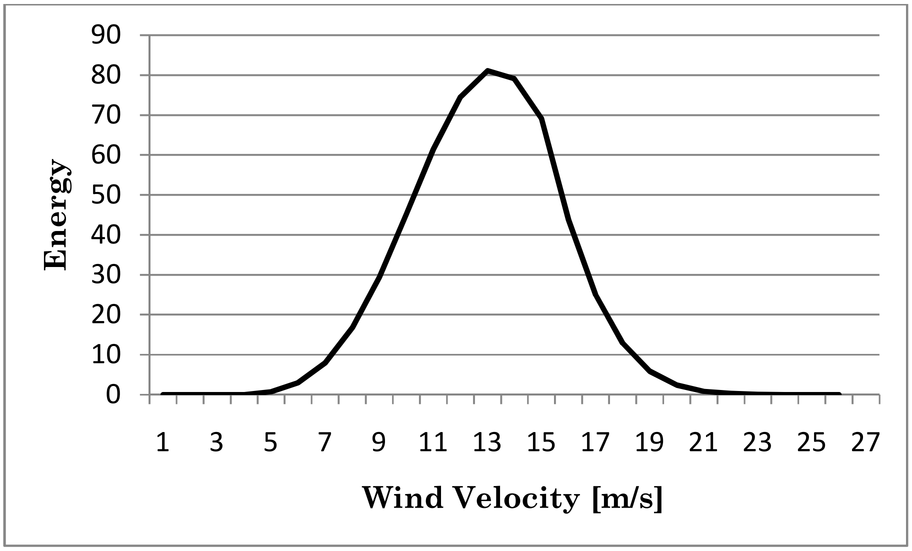


Fig 3.3: Energy Capture Curve for the best scenario

The gross energy captured by the turbine over a period can be computed by adding up the energy corresponding to all possible wind speeds in the regime, at which the system is operational. The gross energy captured annually, i.e. T = 365*24, by each turbine is calculated as:

$$E = T \sum_{V=0}^{25} P_V * f(V) = 8760 * 559.49 = 4{,}901{,}132 \; kWh/yr$$

The total annual gross energy generated in the wind park is calculated by multiplying the above result by the number of turbines in the plant. For 1500 kW turbine:

$$E_T = 34 * 4{,}901{,}132 = 166{,}638{,}488 \; kW/yr \quad \text{i.e}$$

= ***<u>166,638 MWh/yr</u>***

Renewable energy delivered is the amount of wind energy that is transformed into electricity and therefore replaces the energy that would have otherwise been produced by the existing utility system using the base case electricity system [1, 19]. It is this value which is transferred to the ***Financial Summary*** worksheet as input to conduct the financial analysis. Renewable energy delivered is equal to the net amount of energy produced by the wind energy equipment [2, 17]:

$$E_D = E_G * C_L \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots .\ldots \ldots (3.10)$$

Where C_L is the losses coefficient, given by:

$$C_L = (1 - \lambda_a)(1 - \lambda_s)(1 - \lambda_d)(1 - \lambda_m) \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots ..\ldots \ldots .(3.11)$$

Where λ_a = the array losses, λ_s = the airfoil soiling losses, λ_d = the downtime losses, and λ_m = the miscellaneous losses.

The comparison of the gross energy production and renewable energy delivered using the selected WECSs (Scenarios) for the hypothetical 51 MW wind project is depicted as follow.

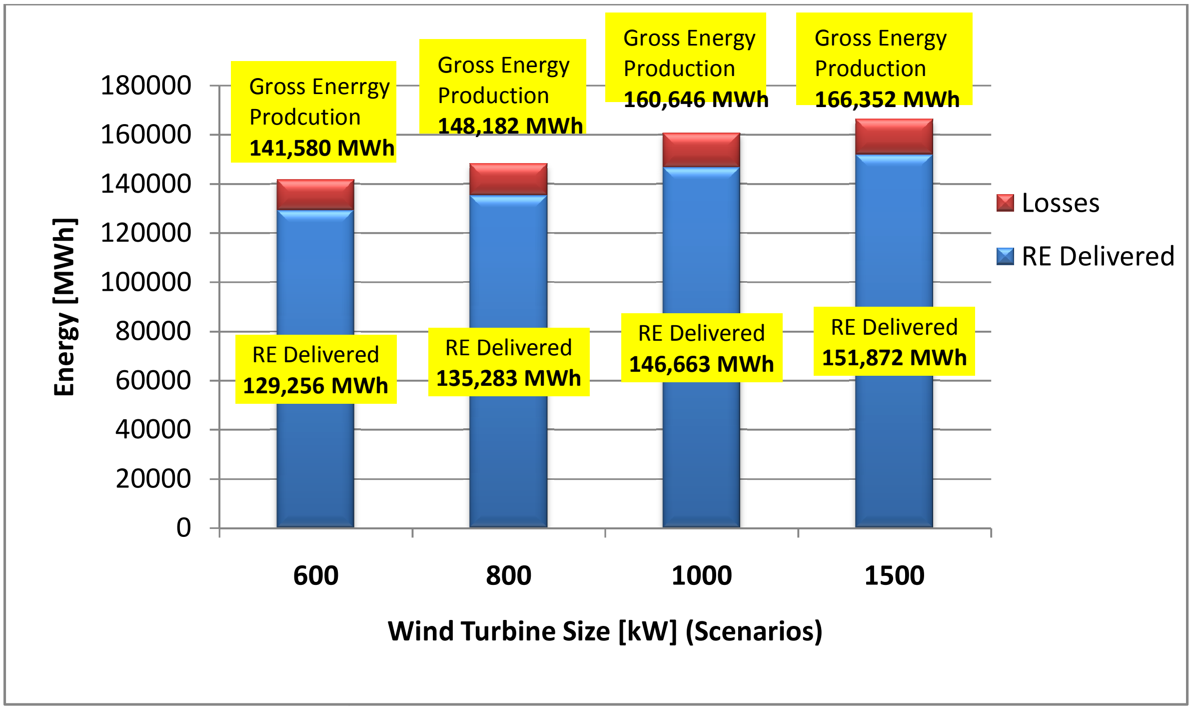


Chart 3.1: Comparison of the Annual Energy Production for the selected WECSs (Scenarios)

As can be seen from the above chart, the scenario with 1500 kW turbine size results in the maximum annual gross energy production of 166,352 MWh. Likewise a maximum RE of 151,872 MWh is delivered by the same scenario, considering 14,480 MWh energy losses due to the array, soiling, other downtime and miscellaneous losses. Second best annual gross energy production of 160,646 MWh is estimated for the scenario with 1000 kW turbine size. In the same way, a maximum RE delivered of the order of 146,663MWh is obtained for this scenario.

The annual gross energy and the RE delivered obtained for the remaining two scenarios, (scenarios with 800 and 600 kW turbine sizes), were not that attractive. These clearly show their lower performance for this site.

3.3.2 Specific Yield

Specific yield is a common criterion in the wind energy industry to evaluate and compare the performance of a wind turbine in conjunction with the wind regime at the site. The specific yield normally ranges from 150 to 1,500 kWh /m^2 per turbine where the low end corresponds to a small wind turbine in a mediocre wind regime and the high end, to a larger wind turbine in a good wind regime [1, 19]. The specific yield Y is obtained by dividing the renewable energy delivered by the swept area of the turbines [2, 19]:

$$Y = \frac{E_C}{NA} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (3.12)$$

Where N is the number of turbines, A is the area swept by rotor of a single wind turbine.

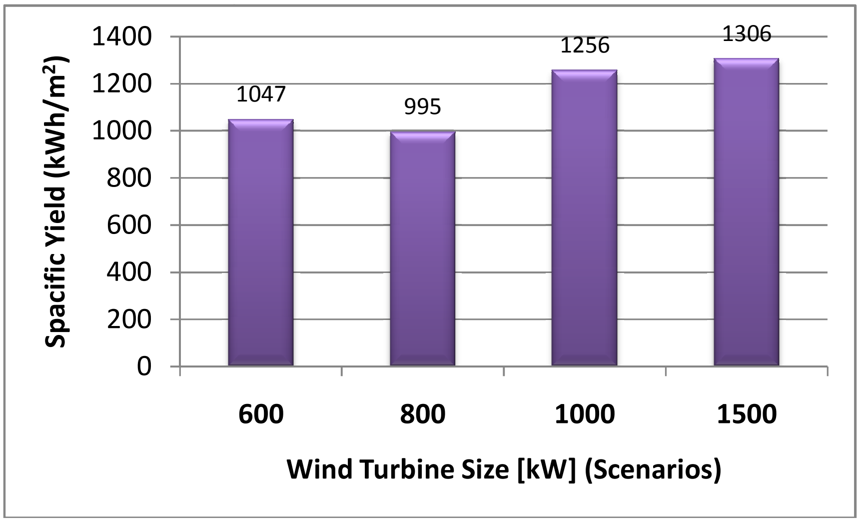


Chart 3.2: Comparison of the Specific Energy Yield for the selected WECSs

As it is shown in the above chart, a maximum specific energy yield of 1306 kWh/m^2 is obtained for the scenario with 1500 kW turbine size. Compared to the resulted specific energy yield for the remaining scenarios, this machine performs best for the wind regime at this site. The energy yield of scenarios with 1000, 800 and 600 kW turbine sizes are 1256 kWh/m^2, 995 kWh/m^2 and 1047 kWh/m^2, respectively.

3.3.3 Wind Plant Capacity Factor

Capacity factor is an indicator of how much energy a particular wind turbine makes in a particular place. Wind power plants have a much lower capacity factor but a higher efficiency than typical fossil fuel plants. A higher capacity factor is not an indicator of higher efficiency or vice versa.

Wind plant capacity factor represents the ratio of the average power produced by the plant over a year to its rated power capacity. It is calculated as follows [2, 20]:

$$PCF = \left(\frac{E_D}{WPC * h_Y}\right) * 100 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3.13)$$

Where E_D is the renewable energy delivered, expressed in kWh, WPC is the wind plant capacity, expressed in kW, and h_Y is the number of hours in a year.

The wind plant capacity factor will typically range from 20 to 40%. The lower end of the range is representative of older technologies installed in average wind regimes while the higher end of the range represents the latest wind turbines installed in good wind regimes.

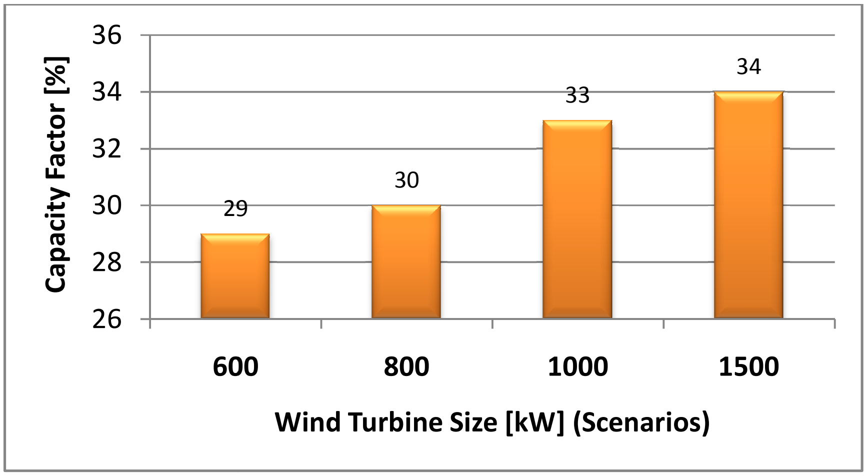


Chart 3.3: Comparison of the Wind Plant Capacity Factors for the selected WECSs

The chart clearly indicates very close results for the first two scenarios; capacity factors of 29% and 30% for 600 and 800 kW turbine sizes, respectively. In the same way, for the other two scenarios, capacity factors of the order of 33% and 34% are obtained for the 1000 and 1500 kW turbine sizes, respectively.

Results obtained for the last two scenarios are much better than the first two scenarios. Of which a maximum capacity factor of the order of 34% is obtained for scenario with 1500 kW turbine size.

Chapter 4

Wind Energy Project Cost Estimation

4.1 Background

Whenever the costs for wind energy project are estimated, the first thing that comes in one's mind are "What is an acceptable level of accuracy for project cost estimate?" and ‘‘How much do these studies typically cost?". The range of accuracy of estimates equals the estimated cost divided by final cost, assuming constant currency value.

The accuracy of cost estimate depends on the type and level of analysis for the project. Typically, a pre-feasibility level, which requires a less detailed analysis, cost analysis should be accurate within 40 to 50%. However, this accuracy will depend on the expertise of the study team, the scale of the project being considered, the level of effort put forward to complete the pre-feasibility study and availability of accurate information. But for feasibility level analysis a more detailed cost appraisal is usually required. Therefore, feasibility level cost analysis should be accurate within ***15 to 25%*** of the total initial project costs.

It is possible to estimate those costs which are associated with a wind energy project, both for pre-feasibility and feasibility study, by RETScreen software through its cost analysis worksheet. These costs are addressed from the initial or investment cost standpoint and from the annual or recurring cost standpoint. These terms are explained in detail below.

4.2 Initial Costs

In the initial costs, the major categories include costs for preparing a feasibility study, performing the project development functions, completing the necessary engineering, purchasing and installing the energy equipment, construction of the balance of plant and costs for any other miscellaneous items. The following table suggests typical ranges of relative costs, for the main cost categories, according to the wind farm class being analyzed [1].

Table 4.1: Relative Initial Costs for Wind Energy Projects.

Main Cost Category	**Large Wind Farm (%)**	**Small Wind Farm (%)**	**Single Turbine (%)**
Feasibility Study	Less than 2	1 to 7	Project specific
Development	1 to 8	4 to 10	,,
Engineering	1 to 8	1 to 5	,,
RE Equipment	67 to 80	47 to 71	,,
Balance of Plant	17 to 26	13 to 22	,,
Miscellaneous	1 to 4	2 to 15	,,

As it is shown in the above table, the energy equipment and balance of plant are the two cost categories showing the strongest dependence on the number of wind turbines that make up the wind farm. Hence, the larger the wind farm, the more relative weight these two categories represent. The following table presents the relative initial costs assumed in this study under different wind farm scenarios.

Table 4.2: Relative Initial Costs for Different Wind Farm Scenarios (Thousand US$).

Wind Project Cost Items	**Wind Turbine Size Scenarios [kW]**							
	600		**800**		**1000**		**1500**	
	Cost	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**
Feasibility Study	170.6	0.2	170.6	0.2	170.6	0.2	170.6	0.2
Development	277.6	0.3	277.6	0.4	277.6	0.4	277.6	0.4
Engineering	612	0.8	612	0.8	620	0.8	636	0.9
RE Equipment	66,320.2	83.1	64,093.2	82.8	63,297.4	83.3	59,785.6	83.9
Balance of Plant	6,953.5	8.7	6,947.4	9.0	6,421.5	8.5	5,493.5	7.7
Miscellaneous	5,440.5	6.8	5,281.9	6.8	5,188.7	6.8	4,874.6	6.8
Total	**79,774.4**	**100**	**77,382.8**	**100**	**75,975.8**	**100**	**71,237.9**	**100**

4.2.1 Feasibility Study

Once a potential cost-effective wind energy project has been identified through the RETScreen pre-feasibility analysis process, a more detailed feasibility analysis study is normally required. Feasibility study include such items as a site investigation, a wind resource assessment, an environmental assessment, a preliminary project design, a detailed cost estimate, a GHG baseline study and a monitoring plan and a final report. Feasibility study project management and travel costs are also normally incurred [1, 29].

In this study, costs associated with the feasibility study are assumed to be the same for all scenarios. For large wind farm, feasibility study should not exceed 2% of the total wind energy project cost [1].

- The time required to gather data during site investigation typically falls between 2 and 8 person-days. The average personnel per daily fees range from $200 to $800 [1]. Here it is assumed 4 person-days and daily fees of $400.
- The costs of a one year wind resource assessment typically falls between $10,000 and $25,000 per meteorological tower [1]. Here 2 towers each costing $20,000 are taken.
- The time required for environmental assessment typically falls between 1 and 8 person-days. The average per daily fees ranges from $200 to $800 [1]. Here it is assumed 4 person-days and daily fees of $400.
- The number of person-days required for preliminary design ranges between 2 and 20. The average per daily fees ranges from $200 to $800 [1]. Here it is assumed 10 person-days and daily fees of $400.
- The number of person-days required to complete a wind energy detailed cost estimates ranges between 3 and 20. The average per daily fees ranges from $200 to $800 [1]. Here it is assumed 12 person-days and daily fees of $400.
- The costs for developing GHG baseline studies and monitoring plans for large projects have ranged from $30,000-$50,000 [1]. Here it is taken as $50,000.
- Preparing a feasibility study report will involve between 2 and 15 person-days at a rate of between $200 and $800 per person-day [1]. Here it is taken 8 person-days at rate of $400 per person-day.

- The management of the feasibility study involve between 2 and 8 person-days at a rate of between $300 and $800 per person-day [1]. Here it is taken 6 person-days at rate of $400 per person-day.

Cost estimates associated with the feasibility study of the wind energy project are summarized in the following table.

Table 4.3: Feasibility Study Cost Estimates

Feasibility Study	**Unit**	**Quantity**	**Unit cost [$]**	**Amount [$]**
Site Investigation	p-d*	4	400	1,600
Wind Resource Assessment	met tower**	2	20,000	40,000
Environmental Assessment	p-d	4	400	1,600
Preliminary Design	p-d	10	400	4,000
Detailed Cost Estimate	p-d	12	400	4,800
GHG Baseline Study and MP	Project	1	50,000	50,000
Report Preparation	p-d	8	400	3,200
Project Management	p-d	6	400	2,400
Travel and Accommodation	p-trip***	42	1,500	63,000
Total				**170,600**

* Person-days, ** meteorological tower, *** person-trip

4.2.2 Development

Once a potential wind energy project has been identified through the feasibility study to be desirable to implement, project development activities follow. For some projects, the feasibility study, development and engineering activities may proceed in parallel, depending on the risk and return to the project proponent.

For wind energy projects, there are a number of possible project developers. Currently, a common approach is for private power developers to develop and own wind farms, where the energy is sold to the local electricity utility or major local electric customers. In other cases the electricity utility may develop and own wind farms directly. There are also a number of situations where individual wind turbines are purchased by individual investors or businesses and the energy is then sold back to the utility [1, 33].

Wind energy project development activities typically include costs for such items as power purchase agreement (PPA) negotiations, permits and approvals, land rights, land surveys, GHG validation and registration, project financing, legal and accounting, project development management and travel costs.

In this study, costs associated with the project development activities are assumed to be the same for all scenarios. For a large wind farm, the development cost should fall between 1 and 8% of the total wind energy project cost.

- A Power Purchase Agreement (PPA) negotiation will be required if the project is to be owned privately, rather than utility. So in this project PPA negotiation cost is not considered.
- The permits and approvals for wind energy projects involve between 0 and 400 person-days at a rate of between \$200 and \$800 per person-days [1]. Here it is assumed 100 person-days and daily fees of \$400.
- Since the project is assumed to be owned by the public utility, no land right costs are considered.
- A land survey can take approximately 0 to 100 days to complete at a daily rate of \$400 to \$600 per day [1]. Here it is taken 80 days and daily rate of \$400 per day.
- Acquiring the necessary project financing will involve between 3 and 100 person-days at rate of between \$500 and \$1,500 per person-day [1]. Here it is assumed 50 person-days and daily fees of \$900.
- Legal and accounting support will involve between 3 and 100 person-days at a rate of between \$300 and \$1,500 per person-day [1]. Here it is assumed 50 person-days and daily fees of \$900.
- In most RETScreen case studies, project management costs estimates ranges from 12 to 20% of the total developmental costs. Based on this, the project management costs assumed as 16% of the total developmental costs.

Cost estimates associated with the development activities of the wind energy project are summarized in Table 4.4.

Table 4.4: Project Development Cost Estimates

Development	Unit	Quantity	Unit cost [$]	Amount [$]
PPA negotiation	p-d	0.0	0.0	0.0
Permits and approvals	p-d	100	400	40,000
Land rights	Project	1	0.0	0.0
Land survey	p-d	80	400	32,000
GHG validation and registration	Project	1	40,000	40,000
Project financing	p-d	50	900	45,000
Legal and accounting	p-d	50	900	45,000
Project management	p-yr*	1	45,600	45,000
Travel and accommodation	p-trip	20	1,500	30,000
Total				**277,600**

*person-year

4.2.3 Engineering

The engineering phase includes costs for the wind energy project wind turbines micro-siting, mechanical, electrical and civil design, tenders and contracting, and construction supervision. These costs are detailed below.

For large wind farm, the engineering costs should fall between 1 and 8% of the total wind energy project cost. Table 4.5 summarizes the relative engineering costs of the selected turbines for the feasibility study.

4.2.3.1 Wind Turbines Micro-siting

Upon a decision to construct the wind energy project at the completion of the feasibility study, individual wind turbine micro-siting might be required due to site specific variations in winds due to topography, terrain, obstructions, land cover, etc. for large-scale projects, the bulk of the cost resides in the time invested by the micro-siting team. It can include energy and civil engineers, meteorologists, computer simulation experts and draftsmen. The cost of micro-siting will also include costs for necessary maps and topographical data and may include additional surveying. Depending upon the accuracy and appropriateness of wind resource data, it may be necessary to include the cost for a wind resource modeling experts to prepare a site assessment report.

The cost of modeling will be influenced by the availability of digitized topographical maps and historical and/or recent wind speed data for the site and region. The cost of micro-siting should be based on an estimate of the time required by experts to complete the necessary work. It can involve between 0 and 300 person-days at a rate of between \$200 and \$800 depending on the complexity, from a siting point of view, of the proposed project [1, 37].

As the number of turbines to be installed increases the micro-siting cost will also increases. This is because each turbine needs micro-siting before it is installed. So the micro-siting cost assumed to be high for the scenario with the 600 kW turbines, which contains 85 turbines. The one with 1500 kW turbine sizes will has lesser micro-siting cost compared to the other scenarios.

4.2.3.2 Mechanical Design

The principal mechanical engineering cost will be associated with design and planning of the assembly and erection of equipment. The cost the mechanical engineering should be based on an estimate of the time required by experts to complete the necessary work. It can involve between 2 and 150 person-days at a rate of between \$200 and \$800 [1, 38].

The mechanical design cost for each turbine is given in Table 4.5.

Table 4.5: Estimated Engineering Costs of the Selected Turbines for the Feasibility Study (Thousand US$).

Engineering Cost Items	**600 kW**			**800 kW**			**1000 kW**			**1500 kW**		
	Quant.	**Unit Cost [$]**	**Amount [$]**	**Quant.**	**Unit Cost [$]**	**Amount [$]**	**Quant.**	**Unit Cost [$]**	**Amount [$]**	**Quant.**	**Unit Cost [$]**	**Amount [$]**
WT Micro-siting	200 p-d	0.8	160	180p-d	0.8	144	170 p-d	0.8	136	155 p-d	0.8	124
Mechanical Design	75 p-d	0.8	60	80p-d	0.8	64	90 p-d	0.8	72	110 p-d	0.8	88
Electrical Design	130 p-d	0.8	104	140p-d	0.8	112	145 p-d	0.8	116	150 p-d	0.8	120
Civil Design	80 p-d	0.8	64	85p-d	0.8	68	90 p-d	0.8	72	100 p-d	0.8	80
Tenders & Contracting	150 p-d	0.8	120	150p-d	0.8	120	150p-d	0.8	120	150 p-d	0.8	120
Const’n Supervision	0.8 p-yr	130	104	0.8 p-yr	130	104	0.8 p-yr	130	104	0.8 p-yr	130	104

4.2.3.3 Electrical Design

The principal electrical engineering tasks will be associated with design and planning of construction of the control and electrical protection systems and the electrical interconnection with the existing electrical grid. For instance, the interconnection study will address all safety aspects related to the addition of a new production source on the grid, as well as analyze the impact with respect to the quality of the power delivered. The level of effort will be influenced by the availability of appropriate design information from the wind turbine supplier and interconnection requirements form the utility.

The cost of the electrical engineering should be based on an estimate of the time required by experts to complete the necessary work. It can involve between 3 and 300 person-days at a rate of between \$200 and \$800, depending on the scale and complexity of the project [1, 38].

As an example, large wind farms in the 50 to 100 MW scale range will be at the high end of this range. The electrical design cost for each turbine is given in Table 4.5.

4.2.3.4 Civil Design

The principal civil engineering tasks will be associated with design and planning of construction of the foundations, access roads and other on ground systems. The level of effort will be influenced by the availability of approved design information from the suppliers and site specific information regarding access, soil conditions, surface drainage and other physical conditions.

The cost of civil engineering should be based on an estimate of the time required by experts to complete the necessary work. It can be involved between 3 and 300 person-days at a rate of between \$200 and \$800, depending upon the scale complexity of the project.

As an example, large wind farms in the 50 to 100 MW scale range will be at the high end of this range. The civil design cost for each turbine is given in Table 4.5.

4.2.3.5 Tenders and Contracting

Upon completion of the various engineering tasks, tender documents usually are prepared for the purpose of selecting contractors to undertake the work. Once tenders are released, the contracting process is required to both negotiate and establish contracts for the completion of the project.

The cost of the tendering and contracting process should be based on an estimate of the time required by professionals to complete the necessary work. It can involve between 4 and 300 person-days, depending on the complexity of the project at a rate of between $200 and $800 [1, 39].

The tenders and contracting costs are taken to be the same for all scenarios, as the tender documents are prepared for one project. For this study, it is assumed that tenders and contracting requires a moderate effort and involves 150 person-days (see Table 4.5).

4.2.5.6 Construction Supervision

The construction supervision cost item summarizes the estimated costs associated with ensuring that the project is constructed as designed. Construction supervision is provided either by the consultant overseeing the project or by the equipment supplier, or the project manager. Construction supervision involves regular visits to the job site to inspect the installation.

Construction supervision will involve between 0 and 2 person-years at a rate of between $130,000 and $180,000 per person-year depending on the duration of the project construction schedule [1, 39].

For this study, turbine installation requires about 0.8 person-year - 292 days- of supervision with $130,000 per person-year rating (see Table 4.5). Travel time to the site for construction supervision is in addition to the range given. Travel costs are included in the development section above.

4.2.4 Energy Equipments

The determination of the capital costs of a wind energy system remains to be one of the more challenging subjects in wind engineering. The problem is complicated because wind turbine manufacturers are not particularly anxious to share their own cost figures with the world, or with their competitors. Cost comparisons in the framework of wind turbine research and development projects are particularly difficult. That is, the development costs cannot be compared consistently [24, 434].

The energy equipment includes the wind turbines, associated spare parts and transportation costs. These costs are detailed below.

For a large wind farm, the energy equipment cost is by far the most important cost item of the project. It should fall between 67 and 80% of the total wind energy project cost. The energy equipment cost is summarized in the following table.

Table 4.6: Estimated energy equipment costs of the selected turbines for the feasibility study (Thousand US$)

Energy Equipment Cost Items	**600 kW**		**800 kW**		**1000 kW**		**1500 kW**	
	Quant.	**Cost**	**Quant.**	**Cost**	**Quant.**	**Cost**	**Quant.**	**Cost**
Wind Turbines	85	56,508	64	55,705.6	51	54,825	34	53,040
Spare Parts	-	847.62	-	835.61,566.7	-	822.4	-	795.6
Transportation	85	8,964.6	64	7,552	51	7,650	34	5,950
Total	**66,320.2**		**64,093.2**		**63,297.4**		**59,785.6**	

4.2.4.1 Wind Turbines

A wind turbine consists of all components above the foundation including the tower and a control system to interface to a utility distribution service at a transformer or disconnect switch. Wind turbine towers are an integral part of the wind turbine and it is not normally suggested that alternative be used. Many manufacturers offer a range of tower heights and may offer guyed and free standing lattice and tubular configurations.

The generic cost of (or price) of a wind turbine system is expressed in terms of dollars per kW. The table below gives the specific cost of different sizes of turbines. A 50 to 100% premium can be added for wind turbine specially designed and built to operate in harsh conditions with a minimum of maintenance. The suggested cost typically includes a 1 to 5 year warranty, depending on the manufacturer [1, 40].

Table 4.7: Wind Turbine specific costs

Wind Turbine Size (kW)	**Specific Cost ($/kW)**
10 to 20	2,200 to 2,900
20 to 200	1,500 to 2,300
More than 200	1,000 to 1,600

The values in the above table show that as the wind turbine size increases its specific cost per kW decreases. Based on this, the specific costs per kW for the selected turbine capacities of 600 kW, 800 kW, 1000 kW and 1500 kW are assumed to be 1,108 $/kW, 1,088 $/kW, 1,075 $/kW and 1,040 $/kW, respectively. The model uses the above given specific costs as input to calculate the total wind turbine costs for each turbine size. The total costs for these turbine sizes are given in Table 4.6.

The price of a wind turbine system should be obtained from the manufacturer or its agent. The request for price should include a request for breakdown relative to other cost input data necessary such as spare parts, extended warranty, erection equipment, training programs and shipping [1, 40].

4.2.4.2 Spare Parts

Spare parts necessary to support the wind turbines should be included in the project cost. The after purchase price will most often be significantly higher. The extent of the inventory required will depend in the reliability of the wind turbine, warranty, number of machines at the site, transportation difficulty and availability of off-the-shelf components. The cost of spare parts should normally be requested as an element of the purchase price request from the manufacturer.

The cost allocated to spare parts is best described as a percentage of the total turbine cost. For large wind farms, operating in normal conditions, an inventory of spare parts representing at the most 1.5% of the total turbine cost should suffice [Lynette, 1992]. So the spare parts costs given in Table 4.6 represent 1.5% of the respective total turbine costs.

4.2.4.3 Transportation

Transportation costs for equipment and construction materials will vary widely depending upon the mode of transport available and the location of the project site. In many instances the cost will depend on distance and be based on a volume/weight formula. Costs to handle the material at the receiving end should be considered. In isolated areas, bulk shipments may be received only once a year. Logistic control is extremely important here. Shipping costs should be obtained from shipping agents when the scope of the project, equipment and material are determined.

In order to estimate the transportation costs for the turbines Ashegoda and Mesobo-Harena wind projects were taken as reference. This helps in making the estimated transportation costs somewhat realistic. The estimated transportation costs are summarized in Table 4.6 above.

4.2.5 Balance of Plant

The balance of plant for a wind energy project typically includes a number of items. These items include wind turbines foundations and erection, road construction, transmission line, substation, control and O&M buildings and transportation costs. These costs are detailed below.

For large wind farm, the balance of plant costs should fall between 17 and 26% of the total wind energy project cost [1]. Summary of the balance of plant costs for the selected turbines is given the following table.

Table 4.8: The estimated Balance of Plant costs for the selected wind Turbines (USD)

Balance of Plant Cost Items	**Wind Turbine Size Scenarios [kW]**			
	600	**800**	**1000**	**1500**
Wind Turbines Foundations	2,125,000	2,389,632	2,193,000	1,700,000
Wind Turbines Erection	2,813,500	2,732,800	2,678,520	2,508,520
Road Construction	365,000	325,000	270,000	215,000
Transmission Line	1,520,000	1,370,000	1,150,000	940,000
Substation	0.0	0.0	0.0	0.0
Control & O & M Buildings	62,000	62,000	62,000	62,000
Transportation	68,000	68,000	68,000	68,000
Total Balance of Plant Cost	**6,953,500**	**6,947,432**	**6,421,520**	**5,493,520**

4.2.5.1 Wind Turbines Foundations

Wind turbine foundations include the labor and material, such as forms, concrete, steel frames and anchors, pilings and fabricated parts. The wind turbine foundations will be specific to the wind turbine and to the site. The manufacture should be requested to provide design information and loads data for design of foundations.

Cost estimates for foundations and materials should be requested from contractors in the project area. In some instances the type of foundations used in some areas will be much different than that which might be used in a community where the construction of concrete bases is a standard practice. Transportation of material could be a large portion of the cost.

For large wind turbines, foundation costs typically fall between $10,000 and $50,000 per turbine. For medium wind turbines, it typically ranges between $7,000 to %25,000 per turbine. A more precise estimate can be obtained once the geotechnical survey has been conducted. Foundation costs also depend on the number and exact size of the wind turbines, the type of tower used and the accessibility of the site. Hence, the costs suggested can be significantly higher for isolated project sites [Lynette, 1992] and [Reid, 1996].

Foundation costs for the selected turbine capacities of 600 kW, 800 kW, 1000 kW and 1500 kW are assumed to be $25,000, $37.338, $43,000 and $50,000 respectively. These estimations were decided based on the RETScreen case studies and results from Ashegoda and Mesobo-Harena wind projects. The total costs for these turbines are summarized in Table 4.8 above.

4.2.5.2 Wind Turbines Erection

Wind turbine erection includes labor and rental (or purchase) of equipment. The equipment required may vary from cranes and heavy vehicles to special winches, gin poles and other mechanical equipment specific to the wind turbine being considered. For isolated project sites it will usually be more cost-effective to rent tools and equipments, depending on availability, rather than to purchase and shipment of them to a site.

For large wind farms, wind turbines erection typically represents 4% of the total renewable energy equipment and balance of plant costs [Zond, 1994]. So the erection costs for each turbine, given in Table 4.8, represents 4% of the total renewable energy equipment and balance of plant costs.

4.2.5.3 Road Construction

An access road for construction and an ongoing service road is normally required for a medium to large-scale wind energy project. These requirements will depend on the site selection and the mature of the terrain. There may be seasonal limitations both for constructions activity and for use of roads to transport equipment. At some project sites there may be no need for road construction even if the selected sit in not on existing routes. The location of existing roads is a consideration during site selection.

Cost for road construction typically ranges from $0 to $80,000 per km, but can be as high as $500,000 per km if river crossing are required. The length of the road comprises the length of the access road to the site and the length of the service road on the site, linking the turbines. The anticipated length of the required access and service roads can be determined by topographic maps [1]. Here the cost for road construction assumed to be $50,000 per km.

Here only the service road on the site is considered. Because, the Addis – Nazareth road passes across the edge of the Gorodima hill (where the site is located). as it is shown on the following fig. the required length of service road can be estimated from the row length (RL). The number of row taken is 2 so that it is possible to minimize the array losses.

- For 600 kW Turbine: The numbers of turbines are 85, the diameter and the height of tower is 43 and 46 m respectively, therefore the length of row;
  RL = (No̲ of gaps - 1) * (4Dt) = (43 - 1) * (4 * 43) = 7.224 km

Therefore the length of the service road can be approximated to be 7.3 km. similarly for 800, 1000 and 1500 kW turbines the length of the service road are 6.5, 5.4 and 4.3 km respectively. The total cost of the road construction is given in table 4.8.

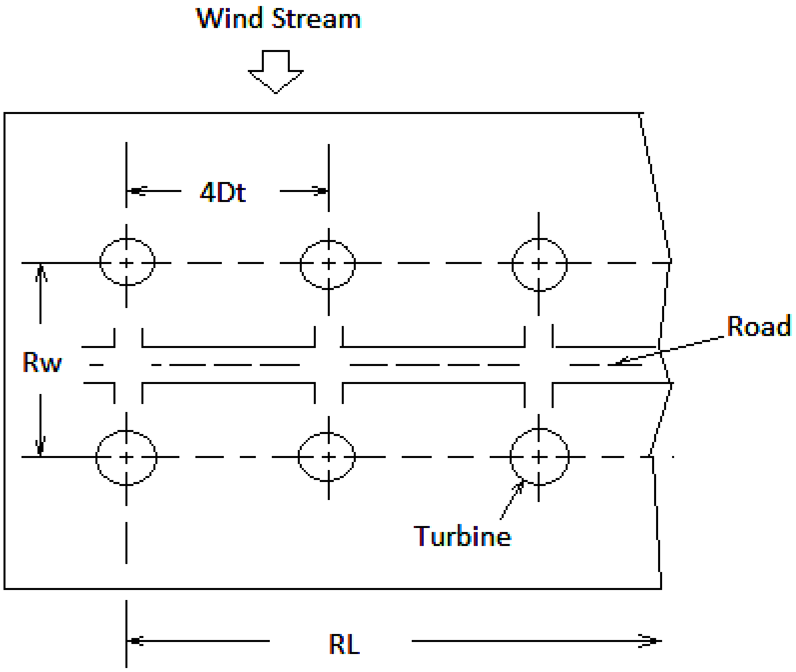


Fig 4.1: Wind Power Plant Layout

For large wind farms, roads typically represent 1 to 3% of total renewable energy equipment and balance of plant costs [Conover, 1994] and [Zond, 1994].

4.2.5.4 Transmission Line

The transmission line cost is site specific and depends on the type, length, voltage and location of the line and the installed capacity of the power plant being developed. Underground lines are normally used to connect the wind turbines in a given row of a wind farm. Their cost can be 2 to 4 times higher than equivalent aerial line. Assuming reasonable accesses, the transmission line cost per km ranges from \$55,000 to \$100,000. Here it is assumed to be \$100,000 per km.

The length of the transmission line can be calculated after knowing the row width (Rw) and the row length (RL). The spacing between the rows is taken as 10Dt, but here it is increased to 12Dt for better performance. For 600 kW turbine the row width is 12*0.043 = 0.516 km. therefore the length of the transmission line between 80 turbines is:

$$L_t = 2 * RL + Rw = (2*7.3)+(12 * 0.043) =15.2 \text{ km}$$

Similarly the lengths of the transmission line for 800, 1000 and 1500 kW turbines are 13.7, 11.5, and 9.4 km respectively. Multiplying the transmission length by the estimated transmission line cost, the total transmission line cost can be calculated. These costs are given in table 4.8.

In areas of permafrost, special soil conditions can increase the cost of line extension significantly. Advice from an expert in local transmission line design or construction may be required in order to estimate this cost [1].

4.2.5.5 Substation

Substation cost is site specific and depends mainly on the voltage and the installed capacity of the power plant being developed. Auxiliary electrical equipment may also include such items as dump loads and heaters, banks of capacitors, monitoring equipment and integrated or SCADA type control systems. The table below provides an indication of the approximate costs involved, assuming reasonable access.

Table 4.9: Estimated Substation costs.

Capacity (MW)	**Voltage (kV)**	**Substation ($)**
0-2	25	250,000
2-5	44	600,000
>5	115	2,000,000

There is already available substation around Nazareth, so for this project there is no need of building a new substation.

4.2.5.6 Control and O&M Buildings

A control building may or may not be necessary. Due to the costs of these buildings, the project developer should try to avoid this requirement where it is practical to do so. A control building may also serve as a location for maintenance work and storage of spare parts and materials. Modern wind turbines can be controlled remotely which may eliminate the need for such a facility. Existing utility locations may be possible alternatives.

Construction costs for buildings will be very high in some communities. Usually a local builder will be able to give a quick estimate for the cost of a suitable new structure or for renovation of an existing space. For large-scale wind energy projects, the O & M control building typically represents 1% of the total renewable energy equipment and balance of plant costs [Vesterdal, 1992]. The control and O & M building costs are given in Table 4.8.

4.2.6 Miscellaneous

This category is for all of the miscellaneous costs that occur during a project and have not been taken into account in the previous sections. For wind energy projects these costs can include training, commissioning, contingencies and interest during construction.

For large wind farm, the miscellaneous costs, excluding contingencies, should fall between 1 and 4 % of the total wind energy project cost [1].

Table 4.10: Estimated miscellaneous costs for the selected wind Turbines (USD)

Miscellaneous Cost Items	**Wind Turbine Size Scenarios [kW]**			
	600	**800**	**1000**	**1500**
Training	72,000	72,000	72,000	72,000
Commissioning	80,000	80,000	80,000	80,000
Contingencies	3,724,297	3,612,641	3,546,955	3,325,766
Interest During Construction	1,564,205	1,517,309	1,489,721	1,396,822
Total Miscellaneous Cost	**5,440,501**	**5,281,309**	**5,188,676**	**4,874,588**

4.2.6.1 Training

Currently no well experienced wind energy experts in the field of wind turbine technology are available in Ethiopia. So there will be a greater need for local trained technicians in order to avoid lengthy repair delays. The cost associated with the training of plant operators and maintenance personnel will depend on the size, complexity and remoteness of the installation.

For a large wind farm, up to 6 maintenance technicians per sections of 50 wind turbines, in additions to 3 operators, may be required. Training costs include professional fees [1].

Training will involve between 2 and 10 people for 1 to 20 days at a rate of between $200 and $800 per person-day depending on the size of the project [1]. For this project, training for 9 people for 10 days at a rate of $800 is assumed (see Table 4.10).

4.2.6.2 Commissioning

Commissioning is the last activity of the construction phase. It consists of operating all the equipment to detect and fix any malfunctions, and ensure that the wind turbines and the wind farm function as guaranteed. Commissioning normally involves the monitoring of the wind plant performance over a set period of time under typical operating conditions. The cost associated with the commissioning of the wind farm will depend on the technology, size and number of turbines of the wind plant and on the skills and experience of the O & M staff. It could also depend on the climate conditions to the extent that a sustainable period of sufficient wind is required to prove the adequate performance of the equipment.

Commissioning will involve between 1 and 8 people for 1 to 30 days at a rate of between \$200 and \$800 per person-day depending on the size of the project [1]. For this project 5 people for 20 days at a rate of \$800 is assumed. The resulting total commissioning cost is given in table 4.10.

4.2.6.3 Contingencies

The allowance made for contingency costs depends on the level of accuracy of the cost estimates. Contingencies are estimated based on a user-selected percentage of the subtotal of all project costs excluding interest during construction.

For this project the cost of contingencies is assumed as 5% of the subtotal of all initial project costs excluding interest during construction (see Table 4.10).

4.2.6.4 Interest During Construction

Interest during construction (short-term construction financing) will vary depending on the duration of construction and the cost of money. Although the construction of a wind far can take up to one year, normally not more than 6 months are required between delivery of the turbines (the most important cost item) and commissioning of the wind farm. The user enters the interest rate (%) and the length of construction in months. The interest cost during construction is then calculated assuming the average debt over the project length in months is 50 % of the subtotal of all project costs.

The cost of interest during construction can vary between 3 and 15% of the project costs. For this project 12 months of construction period with interest cost of 4% of the subtotal of all initial project costs is assumed for all scenarios. The calculated cost of interest during construction for the selected turbines is given in Table 4.10.

4.3 Annual Costs

Wind turbines do not consume any fuel, but neither can they work completely without operating costs [4, 751]. There are a number of annual costs associated with the operation of a wind energy project. These include land lease, property taxes, insurance premium, transmission line maintenance, parts and labor, GHG monitoring and verification, community benefits, travel and accommodation and general and administrative expenses. In addition to these, costs for contingencies are also incurred. These cost items are detailed below and summarized in Table 4.11.

4.3.1 Land Lease and Property Taxes

Land lease costs are annual expenses for the use of the land where the project is being implemented. But there is no land use expenses for government owned projects. The same is true for property taxes so these two costs are not included for this project.

4.3.2 Insurance Premium

This cost item summarizes the annual insurance premium costs and is calculated as a percentage of the total estimated initial costs. As a minimum, insurance is required for public liability, property damage, equipment failure and business interruption. The annual costs for insurance can be significant for an energy project and should be estimated by contacting an insurance broker.

As a rule-of-thumb, the annual cost of insurance for a wind energy project can range between 2 and 4% of project capacity and energy revenues [Conover, 1994] and [Zond, 1994].

Table 4.11: Estimated Annual Operating Costs for all Wind Farm Scenarios (USD)

Annual Cost Items	**Wind Turbine Size Scenarios [kW]**			
	600	**800**	**1000**	**1500**
Insurance Premium	360,500	342,436	323,145	305,145
Transmission Line Maintenance	60,800	41,100	34,500	28,200
Parts and Labor	1,809,591	1,893,966	2,053,284	2,126,206
GHG Monitoring & Verification	6,000	6,000	6,000	6,000
Community Benefits	5,000	5,000	5,000	5,000
Travel and Accommodation	36,000	36,000	36,000	36,000
General and Administrative	227,189	226,016	245,193	250,055
Contingencies	249,908	248,618	269,712	275,061
Total Annual Cost	**2,748,908**	**2,734,794**	**2,966,834**	**3,025,666**

4.3.3 Transmission Line Maintenance

The maintenance of transmission lines associated with a wind energy project will involve periodic clearing of trees (where present) and replacement of parts (e.g. poles, conductor, insulators) that become damaged due to lightning, impact, etc.

The annual cost of transmission line maintenance is estimated based on the capital cost of the transmission line and substation. Annual costs normally range between 3 and 6% of capital costs, depending on the location and communication equipment required (i.e. ease of access, presence of trees, VHF radio network, etc) [1, 48].

Here the annual cost of transmission line maintenance is taken as 4 % of capital costs of the transmission line. This assumption is taken to be common for all scenarios of this project. The annual transmission line maintenance costs are presented in Table 4.11 above.

4.3.4 Parts and Labor

The parts and labor cost item summarizes the cost of spare parts and annual labor required for routine and emergency maintenance and operation of the wind turbines. Operation includes monitoring, regular inspection of the equipment (including routine lubrication and adjustments), snow, ice and dirt removal, scheduled maintenance (internal inspection and maintenance of the turbines), etc.

The cost for parts and labor is best expressed in terms of dollars per kWh produced by the wind energy project. For a large wind farm, this cost falls between 0.007 and 0.024$/kWh with an average around 0.014 $/kWh [Gipe, 1995].

In this study the cost for parts and labor is taken as the average value, which is 0.014 $/kWh. The resulting cost for parts and labor with this assumption is presented in Table 4.11.

4.3.5 GHG Monitoring and Verification

Greenhouse gas monitoring is generally carried out by project proponents in accordance with the data requirements and methods laid out in the monitoring plan. If additional data need to be collected in order to estimate GHG emissions, the cost of collecting these data and quantifying emissions reduction should be estimated. For CDM projects, sustainable developments indicators will also need to be monitored.

For CDM projects, emissions reductions must be verified and certified by a designated operational entity before Certified Emissions Reductions (CERs) are issued. A prescribed rate of $400/day had been set for the staff of designated operational entities or $1,200/day for a team of three [1, 49].

In this study the application of subsides on capital finance to the up-front and CDM periodic costs are considered. This assumption is taken to be common for all scenarios in this study.

4.3.6 General and Administrative

Annual general and administrative costs include the costs of bookkeeping, preparation of annual statements, bank charges, communications, etc. General and administrative costs are project specific and depend on the nature of the business enterprise (e.g. privately-owned with a simple power purchase agreement or utility publicly owned with individual customers).

General and administrative costs can range between 1 to 20% of the annual costs (excluding other costs and contingencies) [1]. Here it is taken as 10% of the annual costs, see Table 4.11 for these costs.

4.3.7 Contingencies

A contingencies allowance should be included to account for unforeseen annual expenses and will depend on the level of accuracy of the operation and maintenance cost estimate section. This is especially true in the case of project in isolated areas. It is common to carry a contingency allowance for at least the replacement of the most expenses component subject to catastrophic failure. The contingencies allowance is calculated based on an estimated percentage of the other operation and maintenance costs. It typically ranges from 10 to 20% of these costs [1].

A 10% contingencies allowance is assumed for this project. The resulting contingencies cost with this assumption for all scenarios is given in Table 4.11 above.

Chapter 5

Financial Feasibility Analysis

5.1 Introduction

The financial analysis is done to check whether or not the wind farm is financially attractive. As in the annual energy production analysis, four scenarios have been considered in the financial analysis of the hypothetical wind farm project:

Scenario I – 85 turbines with 600 kW rated power each

Scenario II – 64 turbines with 800 kW rated power each

Scenario III – 51 turbines with 1000 kW rated power each

Scenario IV – 34 turbines with 1500 kW rated power each

The financial feasibility study is performed in terms of ***internal rate of return (IRR), net present value (NPV), annual life cycle saving (ALCS), year to positive cash flow (YPCF), benefit to cost ratio (B-C)*** *and* ***debt service coverage (DSC)***. With the help of the above financial feasibility indicators, the scenarios are compared with each other to select the best one.

One of the primary benefits of using RETScreen software is that it facilitates the project evaluation process for decision-makers. The financial summary worksheet, with its financial parameters input items (e.g. avoided cost of energy, discount rate, debt ratio, etc.), and its calculated financial feasibility output items (e.g. IRR, Simple payback, NPV etc.), allows the project decision-maker to consider various financial parameters with relative ease.

5.2 Financial Input Parameters

There are many input parameters which are required in order to calculate the financial feasibility indicators. These financial input parameters include the ***Energy selling value, energy cost escalation rate, inflation, discount rate, project life, debt ratio, debt interest rate*** *and* ***debt term***. These input items with their respective assumptions are presented in the section below.

5.2.1 Energy Selling Value

This value typically represents either the ”average” or the ”marginal” unit cost of energy for the base case electricity system and is directly related to the cost of fuel for the base case electricity system.

An energy selling value of 0.07 US$/kWh is taken for this study. This is taken by comparing with the energy selling value for diesel and hydropower power plants. Compared to the selling price of electricity generated from wind power plants in other countries, this value is very less. A lesser value is taken to make the selling price of electricity somewhat comparable with that of Hydropower.

5.2.2 Energy Cost Escalation Rate

Energy cost escalation rate is the projected annual average rate of increase for the avoided cost of energy over the life of the project. This is application of rate of inflation to energy costs which are different from general inflation for other costs.

According to EEPCO, the annual inflation on the current power tariff, energy cost escalation rate, is 2%.

Table 5.1: Assumed Input Parameters for the Financial Feasibility Analysis

Financial Input Parameters	**Unit**	**Values**
Energy selling value	$/kWh	0.07
Energy cost escalation rate	%	2
Inflation	%	2
Discount rate	%	12, 10, 8
Project life	yr	25
Debt ratio	%	90
Dept interest rate	%	5
Debt term	yr	15

5.2.3 Inflation

Inflation is the projected annual average rate of inflation over the life of the project [1, 58]. According to EEPCO, local currency price inflation is assumed to increase by 3.6% annually whereas foreign currency price inflation is assumed to increase by 2.5% annually. Starting from year 2009, the mentioned inflation rates are assumed to decrease to 2% and 3% in 2015 for foreign and local currency, respectively [18, 228].

In this study, annual inflation rate of 2% is assumed for the financial feasibility analysis.

5.2.4 Discount Rate

Discount rate is the rate used to discount future cash flows in order to obtain their present value. The rate generally viewed as being most appropriate is an organization's weighted average cost of capital. An organization's cost of capital is not simply the interest rate that it must pay for long-term debt. Rather, cost of capital is a broad concept involving a blending of the costs of all sources on investment funds, both debt and equity. The discount rate used to assess the financial feasibility of a given project is sometimes called the "hurdle rate", the "cut-off rate," or the "required rate of return". The model uses the discount rate to calculate the annual life cycle savings [1, 58].

According to Ethiopian power system expansion master plan, the agreed economical discount rate is 10% [18]. The financial feasibility study is performed for three discount rates of 8%, 10% and 12%.

5.2.5 Project Life

Project life is the duration over which the financial feasibility of the project is evaluated. Depending on circumstances, it can correspond to the life expectancy of the energy equipment or the term of the debt. although the model can analyze project's life up to 50 years, the project life of a well designed wind energy project falls between 20 and 30 years [1, 58].

In this study a plant life of 25 years is assumed.

5.2.6 Dept Ratio

Dept ratio is the ratio of debt over the sum of the debt and the equity of the project. The debt ratio reflects the financial leverage created for a project; the higher the debt ratio, the larger the financial leverage. The model uses the debt ratio to calculate the equity investment that is required to finance the project. For example, debt ratios typically range anywhere from 0 to 90% with 50 to 90% being the most common [1, 58].

Considering the current economical status of Ethiopia, 90% debt ratio is taken, i.e. 90% of the project cost is financed by debt obtained from foreign lenders. The remaining 10% of the project cost is assumed to be covered by local participation and local materials.

5.2.7 Dept Interest Rate

Dept interest rate is the annual rate of interest paid to the debt holder at the end of each year of the term of the debt. The model uses the debt interest rate to calculate the debt payments. For example, at a minimum, the debt interest rate will corresponds to the yield of government bonds with the same term as the debt term. A premium is normally added to this rate (the “spread”) to reflect the perceived risk of the project [1, 59].

The value taken for debt interest rate depends on the source of the loan. Currently, the interest rate for local loans is 7%, whereas an interest rate of 5% has been used for foreign loan [17, 225]. Since 90% of project cost is assumed to be obtained from foreign lenders; a 5% debt interest rate will be used for the financial feasibility analysis.

5.2.8 Dept Term

Debt term is the number of years over which the debt is repaid. The debt term is either equal to, or shorter than the project life. Generally, the longer the tem, the more the financial viability of an energy project improves. The model uses the debt term in the calculation of the debt payments and the yearly cash flows. The term of the debt normally falls within a 1 to 25 years range. It should not exceed the estimated project life.

The debt term that can be obtained from an International donor loan and/or an Export Credit Guarantee is approximately 15 years [18, 239].

5.2.9 Income Tax Analysis

The two types of taxes that are incurred by energy projects are [17, 224]:

Corporate taxes*:* in accordance with information provided by EEPCO, the company in charge of operating the wind park, i.e. EEPCO, is not subject to corporate taxes. Consequently, the projections do not foresee any related tax estimations.

Import taxes*:* In accordance with present legislation on imports of material and equipment for hydropower plants (HPPs), the company is not liable for related import duties. Although the legislation is not expressively referring to wind parks, as these did not exist at the time relevant legislation was approved, it can be assumed that the legal norms governing HPPs will be applicable also for imports of material and equipment for wind parks.

Therefore, income tax will not be considered in this financial feasibility study.

To include the effect of the additional cash-flow generated by the CDM activity on the project performance, three more additional input parameters are required. These are GHG emission reduction credit, GHG reduction credit duration and GHG credit escalation rate. These input items with their respective assumptions are presented in the section below.

Table 5.2: Additional Financial Input Parameters for CDM Projects

Additional Financial Input Parameters	**Unit**	**Values**
GHG Emission Reduction Credit	$/tCO_2$	6
GHG reduction credit duration	yr	21
GHG credit escalation rate	%	2

5.2.10 GHG Emission Reduction Credit

It is used in conjunction with the net GHG emission reduction to calculate the annual GHG emission reduction income.

For CDM projects, prices for Certified Emission Reductions can be as high as 6 USD/CER [17, 10].

5.2.11 GHG Reduction Credit Duration

This value typically represents the number of years for which the project receives GHG reduction credits. It is used to determine the annual GHG reduction income [1, 56].

For CDM projects, two options are available for the length of the crediting period: (1) a fixed crediting period of 10 years or (2) a renewable crediting period of 7 years that can be renewed twice (for a maximum credit duration of 21 years). If a crediting period of 10 years is selected, once the project has been valid and registered, certified emission reductions (CERs) can be certified and issued for the 10 years of the project without revisiting the baseline. However, in the case of a renewable 7 year crediting period, the project will have to be validated after each 7 years period in order to receive CERs for the subsequent 7 years.

In this study, a renewable crediting period of 7 years that can be renewed twice is assumed.

5.2.12 GHG Credit Escalation Rate

This is the projected annual average rate of increase in the GHG emission reduction credit over the life of the project. This permits the user to apply rated of inflation to the market price of GHG emission reduction credits which may be different from general inflation [1, 56].

Here, a 2% annual average rate of increase in the GHG emission reduction credit over the life of the project is assumed.

5.3 Financial Feasibility Indicators

The output of the various financial input items is explained by the financial feasibility indicators, which are basic in the decision making processes. The financial feasibility study is performed for three discount rates of 8%, 10% and 12%. The financial feasibility indicators used in this wind energy project evaluation processes are elaborated as follows.

5.3.1 Internal Rate of Return – IRR

IRR represents the true interest yield provided by the project equity over its life. It is also referred to as the return on investment (equity) (ROI) or the time-adjusted rate of return. It is calculated by finding the discount rate that causes the net present value of the project to be equal to zero. The IRR is calculated on a nominal basis that is including inflation [1, 65]. The project is feasible if the IRR is greater than the agreed economic discount rate, which is 10%.

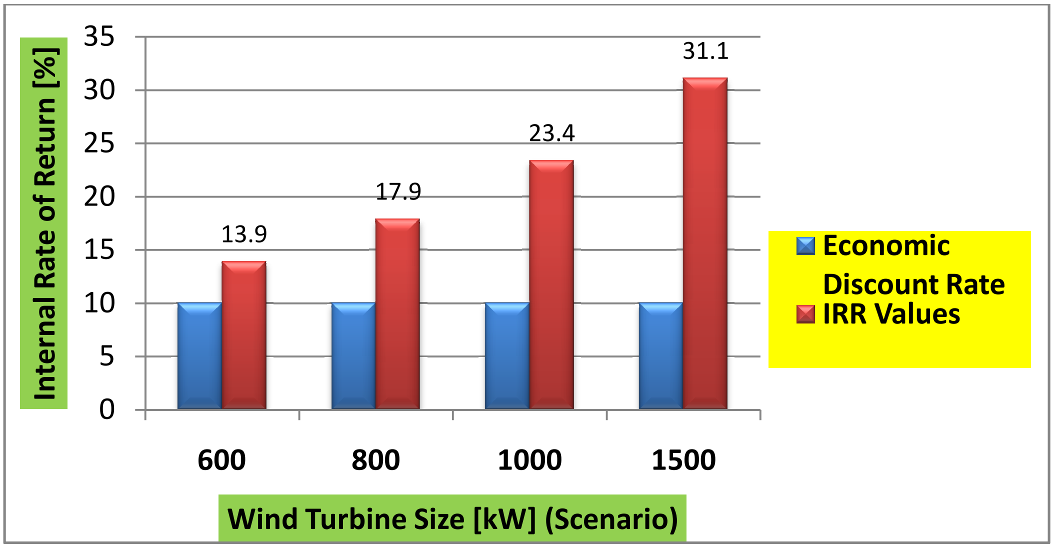


Chart 5.1: Comparison of IRR Values from Different Wind Farm Scenarios

Chart 5.1 shows comparison of the resulted IRR values with the economic discount rate for all wind farm scenarios. For all scenarios, the calculated IRR values are greater than the economic discount rate, which is 10%. Under these conditions, the wind project is financially feasible for all wind farm scenarios. Scenario IV, the one with 1500 kW wind turbine size, has the best IRR values (31.1%) compared to the remaining wind farm scenarios.

5.3.2 Net Present Value –NPV

NPV is the value of all future cash flows, discounted at the discount rate, in today's currency. Under the NPV method, the present value of all cash inflows is compared against the present value of all cash outflows associated with an investment project. The difference between the present values of these cash flows, called the NPV, determines whether or not the project is generally a financially acceptable investment. Positive NPV values are an indicator of a potentially feasible project. In using the net present value method, it is necessary to choose a rate for discounting cash flows to present value [1, 67].

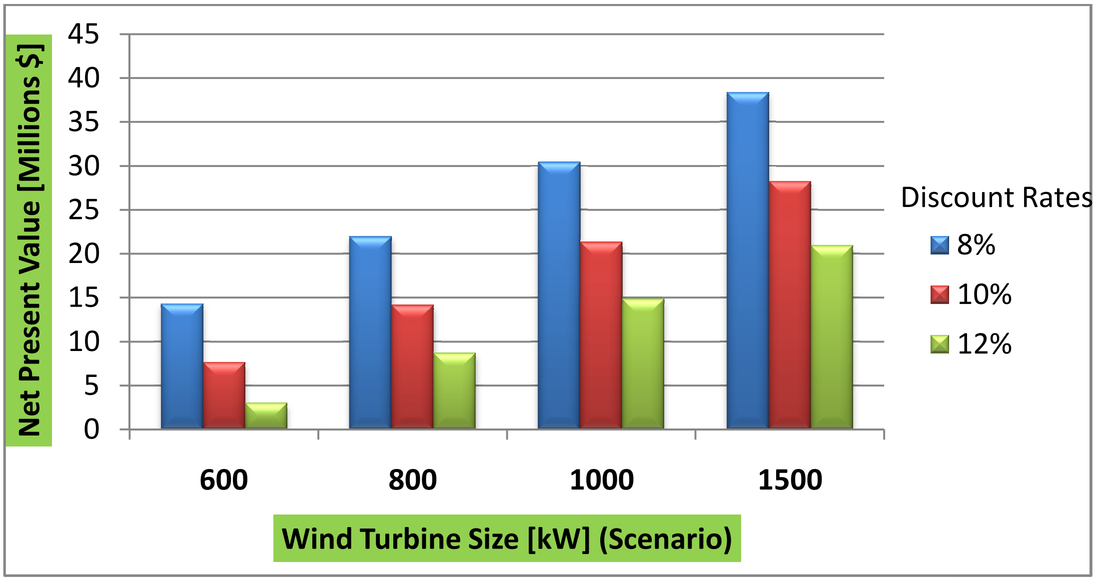


Chart 5.2: Comparison of NPV for Different Scenarios Using Different Discount Rates

The NPV of all wind farm scenarios is calculated using three different discount rates (see Chart 5.2). A positive NPV is obtained for all scenarios in all discount rates. This clearly indicates that Nazareth wind farm is financially feasible for all types WECS used in this study.

The comparison using the economical discount rate, i.e. 10%, indicates that the scenario with 1500 kW turbine size has the maximum NPV of $28,244,174. The NPV of the scenarios with 1000 kW, 800 kW and 600 kW turbine sizes, calculated at 10% discount rate, are $21,335,203, $14,153,642 and $7,616,569, respectively.

5.3.3 Annual Life Cycle Savings –ALCS

Annual life cycle saving is the levelized nominal yearly savings having exactly the same life and net present value as the project. The annual life cycle savings are calculated using the net present value, the discounted rate and the project life [1, 67].

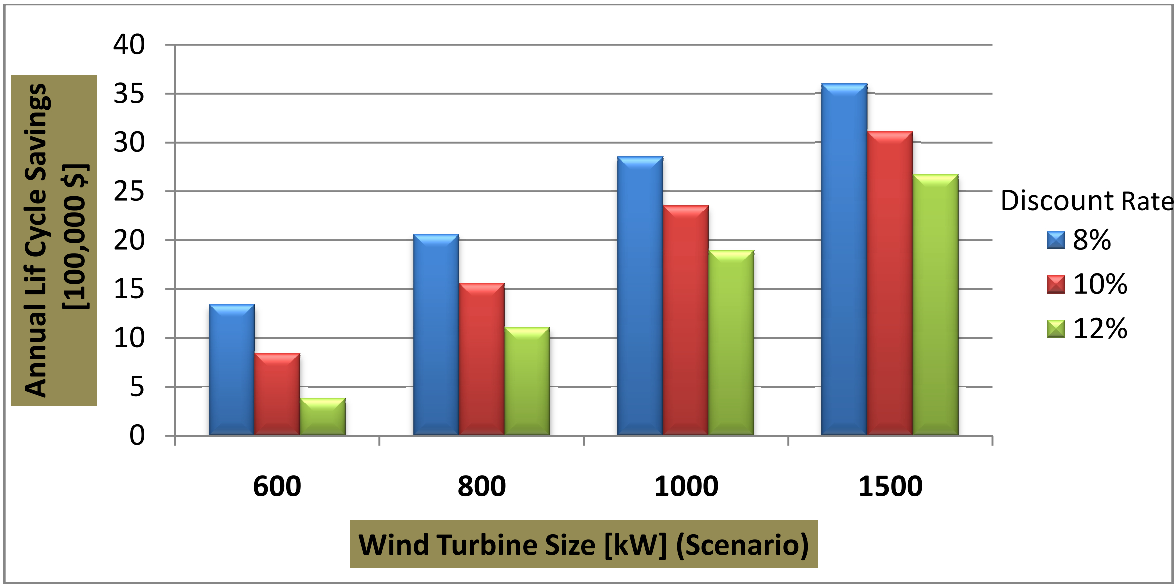


Chart 5.3: Comparison of ALCS for Different Scenarios Using Different Discount Rates

As ALCS are calculated using the results of NPV, likewise the resulted outcomes for ALCS follow the same trend. Here also discount rates of 8%, 10% and 12% are used in order to compare ALCS of all wind farm scenarios. As it is indicated in Chart 5.3, for all discount rates, the scenario with 1500 kW wind turbine size has the maximum ALCS.

Using the economical discount rate (10%), a maximum value of $3,111,606 ALCS is obtained for 1500 kW turbine. The ALCS of wind farm scenarios with 1000 kW, 800 kW and 600 kW turbine sizes, calculated at this economical discount rate, are $2,350,459, $1,559,279 and $839,103, respectively.

5.3.4 Year-to-Positive Cash Flow – YPCF

It represents the length of time that it takes for the owner of a project to recoup its own initial investment out of the project cash flows generated. The year-to-positive cash flow considers project cash flows following the first year as well as the leverage (level of debt) of the project, which makes it a better time indicator of the project merits than the simple payback [1, 66].

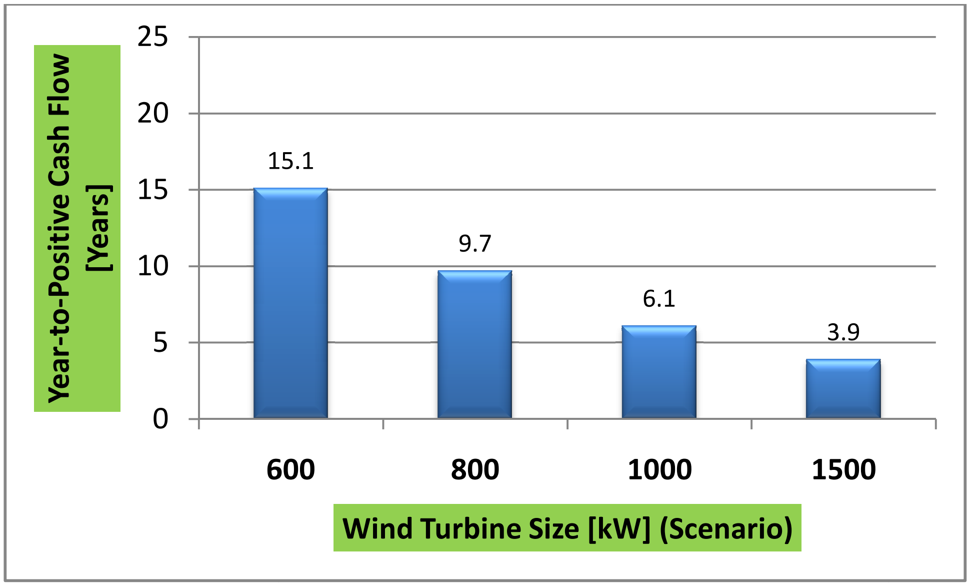


Chart 5.4: Comparison of Year-to-Positive Cash Flow for Different Wind Farm Scenarios

The year-to-positive cash flow differs from the discounted payback indicator in that it considers the nominal value of future cash flows rather than the discounted value of future cash flows.

The above chart clearly indicates that a big distinction occurs between the resulted year-to-positive cash flows of wind farm scenarios. For Scenario IV (1500 kW), it takes only 3.9 years to recoup its own initial investment out of the project cash flows generated. In case of Scenario I (600 kW), it takes more than 3 times higher period in order to recoup its initial investment.

The YPCF of wind farm scenarios with 1000 and 800 kW turbine sizes are 6.1 and 9.7 years respectively.

5.3.5 Benefit-Cost (B-C) Ratio

The net benefit-cost ratio is the ratio of the net benefits to costs of the project. Net benefits represent the present value of annual revenues (or savings) less annual costs, while the cost is defined as the project equity.

Ratios greater than 1 are indicative of profitable projects. The net benefit-cost ratio, similar to the profitability index, leads to the same conclusion as the net present value indicator [1, 67].

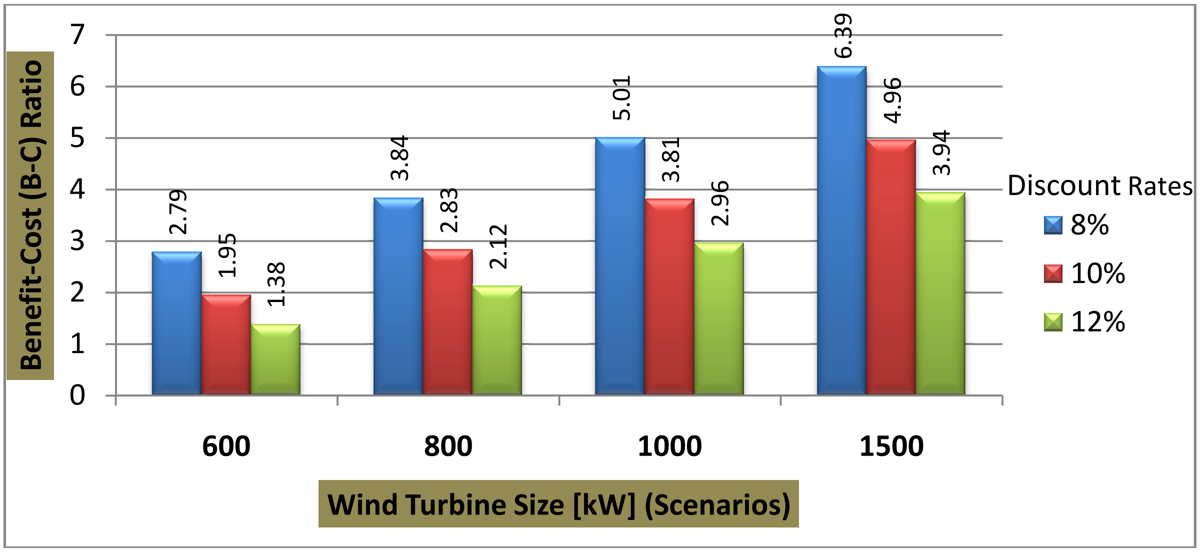


Chart 5.5: Comparison of B-C Ratios for Different Scenarios Using Different Discount Rates

The benefit to cost ratios of all wind farm scenarios are calculated using 8, 10 and 12% discount rates. As indicated in the above chart, for all scenarios in all discount rates, a benefit to cost ratios of greater than 1 is obtained. Therefore, Nazareth wind farm is profitable under all scenarios.

Using the economic discount rate (10%), a maximum benefit to cost ratio of 4.96 is obtained for Scenario IV (1500kW). The benefit to cost ratios of scenarios with 1000 kW, 800 kW and 600 kW turbine sizes are 3.81, 2.83 and 1.95, respectively.

5.3.6 Debt Service Coverage Ratio – DSCR

The debt service coverage is the ratio of the operating benefits of the project over the debt payments. This value reflects the capacity of the project to generate the cash liquidity required to meet the debt payments. It is calculated by dividing net operation income or savings (net cash flows before depreciation, debt payments and income taxes) by debt payments (principal and interest). The model calculates the debt service coverage for each year of the project and reports the lowest ratio encountered throughout the term of debt [1, 69].

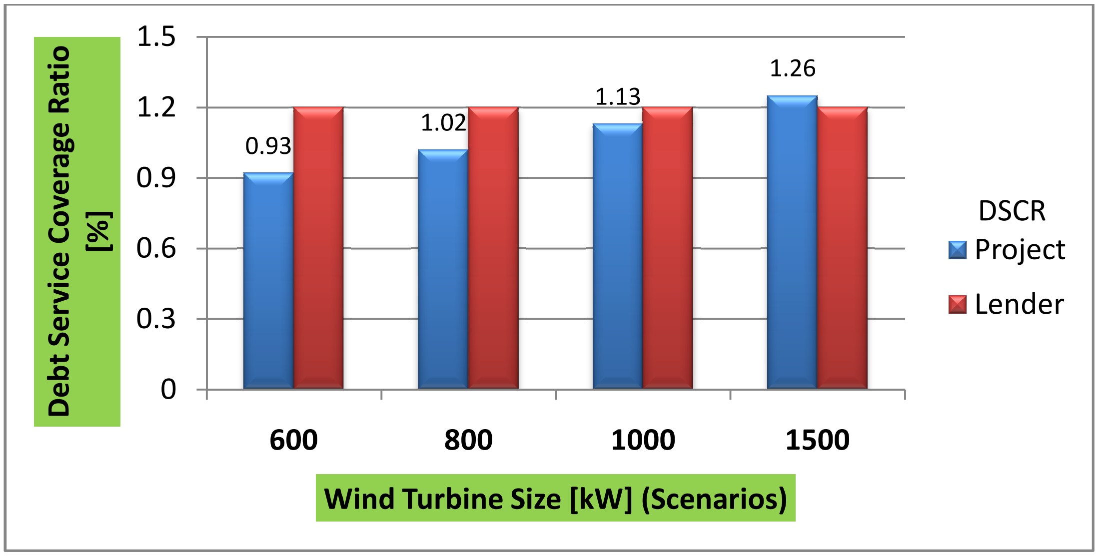


Chart 5.6: Comparison of DSCR of Wind Projects Versus Minimum Lender Requirement

Conventionally, the lender will require that a minimum DSCR of **1.20** be upheld during the amortization period, to ensure that the project can meet its upcoming debt commitments with sufficient buffer [17, 238].

The only scenario that meets the minimum DSCR required by the lender is Scenario IV. Using this scenario, a DSCR of **1.26** is obtained which is sufficient enough. The obtained DSCRs for the remaining wind farm scenarios are below the minimum lender requirements. Therefore, only Scenario IV is eligible in order to get the required loan for the wind project from the lender.

Table 5.3: Summary of the Financial Feasibility Analysis Results for All Wind Farm Scenarios

Discount Rate [%]	**Wind Turbine Size Scenario [kW]**	**Financial Feasibility Indicators**							
		IRR	**NPV [$]**	**ALCS [$]**	**B-C**	**SPP [yr]**	**YPCF [yr]**	**DSCR**	**Energy Production Cost [$/kWh]**
8	600	13.9	14,310,653	1,340,605	2.79	12.7	15.1	0.93	0.0614
10			7,616,569	839,103	1.95				0.0646
12			3,007,626	383,472	1.382				0.0675
8	800	17.9	21,965,190	2,057,672	3.84	11.5	9.7	1.02	0.0570
10			14,153,642	1,559,279	2.83				0.0600
12			8,680,091	1,106,711	2.12				0.0628
8	1000	23.4	30,454,073	2,852,900	5.01	10.4	6.1	1.13	0.0539
10			21,335,203	2,350,459	3.81				0.0566
12			14,858,575	1,894,468	2.96				0.0590
8	**1500**	**31.1**	38,399,722	3,597,239	6.39	**9.4**	**3.9**	**1.26**	0.0504
10			**28,244,174**	**3,111,606**	**4.96**				**0.0528**
12			20,950,171	2,671,146	3.94				0.0550

5.4 Cumulative Cash Flows Graph

The cumulative cash flows are plotted versus time in the cash flows graph. The graph is based on the values of the net flows accumulated from year 0. Here the cumulative cash flows graph is presented for the 1500 kW turbine size.

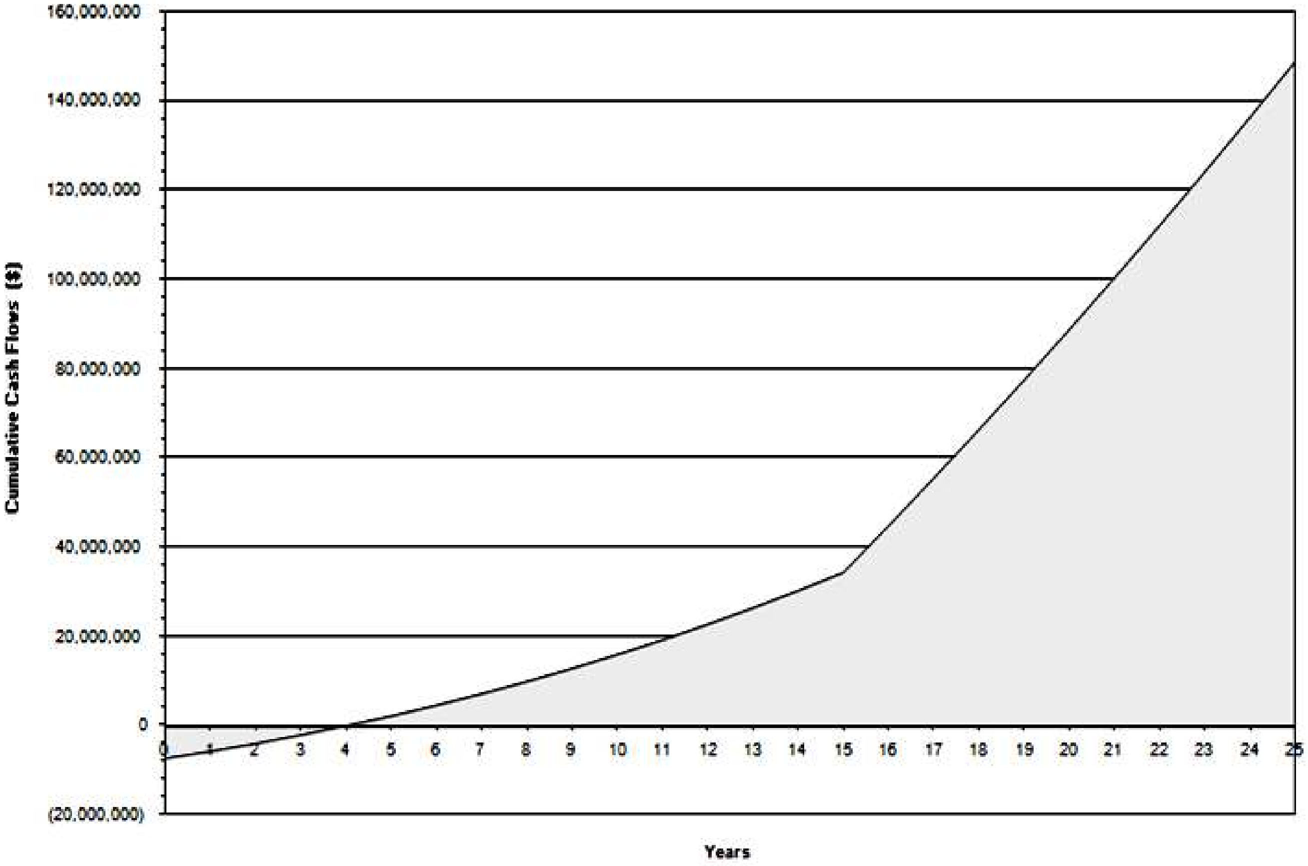


Fig 5.1: The Cumulative Cash Flow Graph of 1500 kW Turbine Size, from RETScreen Model

Chapter 6

Clean Development Mechanism (CDM) Assessment

6.1 Introduction

The Clean Development Mechanism (CDM) is one of the "flexibility" mechanisms defined in the Kyoto Protocol. Article 12 of the 1997 Kyoto protocol establishes the CDM as the international regulatory framework for foreign direct investments in additional GHG mitigation projects in developing countries. With the CDM, investors from industrialized counties and countries with economies in transition, Annex-I countries, will be able count real, measurable, and long- term emissions reductions achieved in developing countries against their commitment to reduce GHG emissions. The protocol aimed at promoting sustainable infrastructure projects in developing countries whilst simultaneously reducing greenhouse gas emissions.

Through RETScreen software it is possible to evaluate the proposed wind project in both domestic and international markets, including projects that fall under the Kyoto Protocol's CDM. The RETScreen GHG analysis worksheet, with its emission related input items (e.g. fuel mix) and its calculated emission factor output items (e.g. GHG emission factor), allows the decision-maker to consider various emission parameters with relative ease. The software also estimates the quantity of credits (GHG reduction income) that the CDM project may generate.

6.2 Current Status of CDM in Ethiopia

There are two main criteria in order to be eligible for CDM. First, the host country like Ethiopia needs to be parties of the United Nations Framework Convention on Climate Change (UNFCCC) and the Kyoto Protocol. Second, the host country needs to have established a Designated National Authority (DNA) for the CDM, which co-ordinates the CDM approval process on the national level on behalf of the host country's government.

Ethiopia has been registered with Kyoto protocol on GHG emissions in April 2005 as a "non-Annex I state". Hence, it fulfills the first criteria.

Furthermore, Ethiopia has established a designated national authority (DNA) for the CDM, namely the Ethiopian Environmental Protection Authority (EPA).

6.3 CDM Project Cycle

Developing countries and transition economies may host a project and benefit from CDM as an additional co-finance source. A project sponsor can be either the host country or usually a project sponsor of an Annex I country. In the case of a wind energy project, the owner of the wind park in a non-annex I country generates revenues from sales in the national market and also from the sale of Certified Emission Reduction (CER) credits. The structure of CDM is depicted as follow [18, 214].

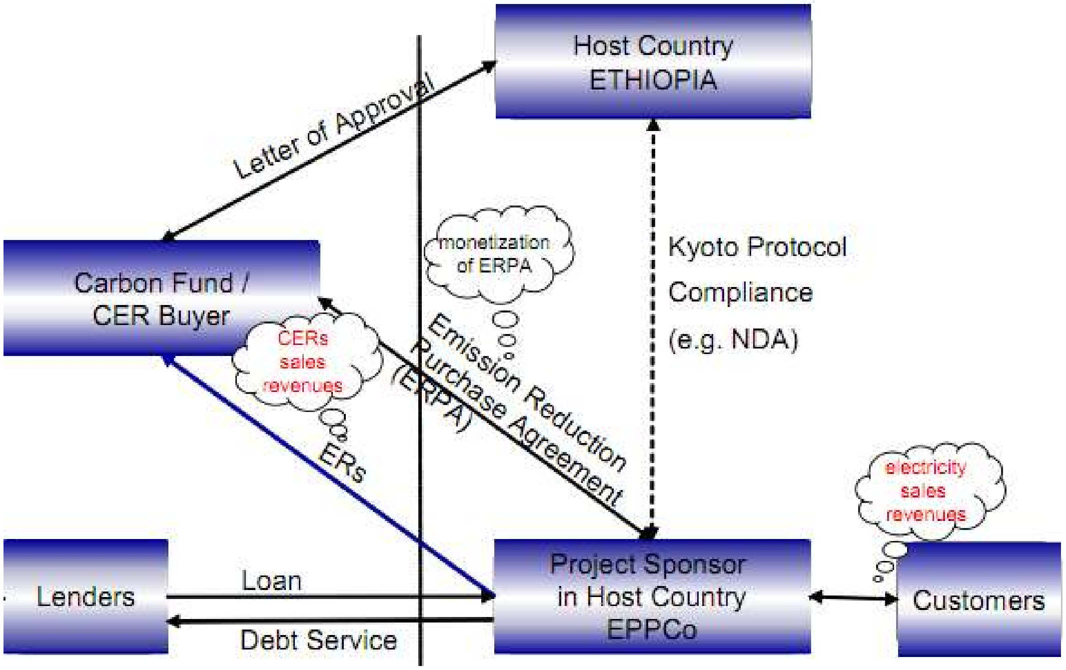


Fig 6.1: CDM structure

CERs can be sold to carbon exchange or to a CER acquisition program such as a carbon fund. Carbon funds offer the opportunity to project owner to close an Emission Reduction Purchase Agreement (ERPA) for the whole CER crediting period, usually 10 years, which avoids risks of oscillating CER market prices.

A potential buyer for the CERs generated by a wind park project could be found, for example, through the Community Development Carbon Fund of the World Bank, which links small scale projects seeking carbon finance with companies, governments, foundations, and through NGOs looking for improvement of livelihoods in local communities and obtain verified Emission Reductions. The advantage of collaborating with an established carbon fund include, for example [18, 209]:

- The signing of a long term ERPA (likely to be characterized by a low price, but with the guarantee of having an assured buyer); and
- Possibility to have a buyer/investor which covers the associated up-front payments.

Under the second point, the target would be to find and investor willing to overtake the up-front costs, which relate to, for example:

- The preparation of a Project Design Document (PDD);
- The project validation by a Designated Operational Entity (DOE); and
- Cost incurred for registration at the UNFCCC CDM Executive Board.

6.4 Baseline

The baseline for a CDM project is the scenario that reasonably represents the anthropogenic or human-induced GHG emissions that would occur in the absence of the CDM project. Since there are several possible ways of calculating baselines, a project developer should select the approach that is most simple, provides the highest returns and easy to justify. In order to estimate the baseline emission factor, by which CO2 emission reductions are calculated for a CDM project, the approved consolidated baseline methodology ACM0002, which is standardized approach, is selected.

The ACM0002 methodology is applicable because the proposed project activity:

- Implies electricity capacity additions from wind sources;
- Does not imply switching from fossil fuels to renewable energy at the site of the project activity; and

- It's geographic and system boundaries can be clearly identified and information on the characteristics of the grid is available.

The combined margin emission factor of Ethiopian base case electric system is calculated based on the UNFCCC "tool to calculate the emission factor for an electricity system", which is an essential requirement for CDM projects. More than 70% of the UNFCCC large scale methodologies require the combined margin factor of the electricity system, which holds true for ACM0002 consolidate baseline methodology. The combined margin emission factor of Ethiopian electric system is given in the following table [14].

Table 6.1: Calculated emission factor values for Ethiopian grid system 2005-07

Project Activities	CO_2 Emission Factors [tCO_2/MWh]		
	Operating Margin (2005-2007)	Build Margin (2007)	Combined Margin (2007)
Wind and Solar power generation activities	0.00715	0.00467	**0.00653**
All other project activities	0.00715	0.00467	0.00591

As can be observed from the above table, the combined margin CO_2 emission factor for the base case electricity system (baseline) is 0.00653 tCO_2 /WMh. This is because; the national grid is highly dominated by hydropower, which is expressed in the very low combined margin CO_2 emission factor. In 2007, 99% of the produced electricity was generated by hydropower, which builds the existing and future main resource. In 2005, the emitted CO_2 emission via thermal plants was about 42,000 tons and decreased to 7,000 tons in 2007. The emissions were caused by the installed power plants Kaliti, Awash 7 kilo and Dire Dawa, which were built to ease energy shortage caused by drought and to reduce load shedding.

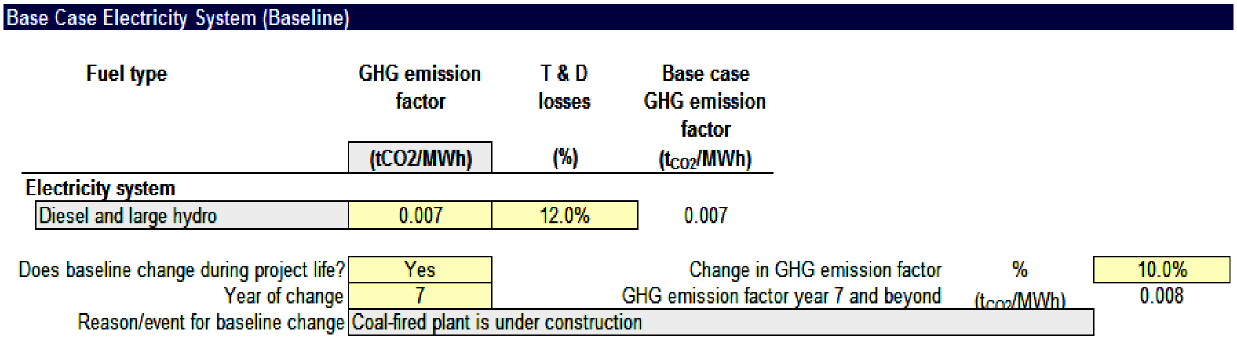
6.5 GHG Emission Reduction Analysis

It is possible to calculate the GHG emission reduction potential of the proposed wind energy project by first computing baseline emission factor. But the baseline emission factor for Ethiopian electric system is already calculated and available as a reference. Therefore, the combined emission factor given in Table 6.1 is used as an input to RETScreen software, so as to calculate the tons of CO_2 reduced by each scenario. For this the RETScreen user-defined emission reduction analysis option is used.

Input parameters other than the emission factor required for the model includes T&D losses, baseline year of change and GHG credits transaction fee. These terms are described in the following section.

T&D losses include all energy losses between the power plant and the end-user. This value will vary based on the voltage of transport lines, the distance from the sight of the energy production to the point of use, peak energy demand, ambient temperature and electricity theft. As a first estimate, T&D losses taken as between 10 to 20% in grids located in developing countries. So, for this project, it is taken to be 12%.

The project baseline will not stay constant throughout the project life. This is because of the addition of new generating units on the grid in the coming years. A 100 MW Coal power plant (Yayu Coal-Fired Power Station) is currently under planning, the average emission factor of the Ethiopian grid is expected to increase 10% instead of decreasing in the second and third period [17]. Due to this, the change in GHG emission factor is taken to be 10% increment for the next crediting periods.



Base Case Electricity System (Baseline)

Fuel type	GHG emission factor (tCO2/MWh)	T & D losses (%)	Base case GHG emission factor (t_{CO2}/MWh)
Electricity system			
Diesel and large hydro	0.007	12.0%	0.007

Does baseline change during project life? Yes

Year of change 7

Reason/event for baseline change Coal-fired plant is under construction

Change in GHG emission factor % 10.0%

GHG emission factor year 7 and beyond (t_{CO2}/MWh) 0.008

Fig 6.2: RETScreen Base Case Electricity System Worksheet

As can be seen from Fig. 6.2, the GHG emission factor for year 8 and beyond is 0.008 t CO_2/MWh.

The annual reduced amount of GHG emission, from entering into the local atmosphere, in each scenario is summarized in the following table. The annual GHG emission reduction is calculated as the product between the End-use annual energy delivered and the base case GHG emission factor. The scenario with 1500 kW wind turbine size has the maximum annual GHG emission reduction potential, which is 1,014 tons of CO_2 for 1 to 7 year of occurrence and 1,116 tons for year 8 and beyond.

Table 6.2: GHG Emission Reduction Summary for All Scenarios

Wind Turbine Size Scenario [kW]	**Year of Occurrence [yr]**	**Base Case GHG Emission Factor [tCO_2/MWh]**	**End-use Annual Energy Delivered [MWh]**	**Annual GHG Emission Reduction [tCO_2]**
600	1 to 7	0.007	118,916	863
	8 and beyond	0.008	118,916	949
800	1 to 7	0.007	121,755	903
	8 and beyond	0.008	121,755	994
1000	1 to 7	0.007	131,997	979
	8 and beyond	0.008	131,997	1,077
1500	1 to 7	0.007	136,685	1,014
	8 and beyond	0.008	136,685	1,116

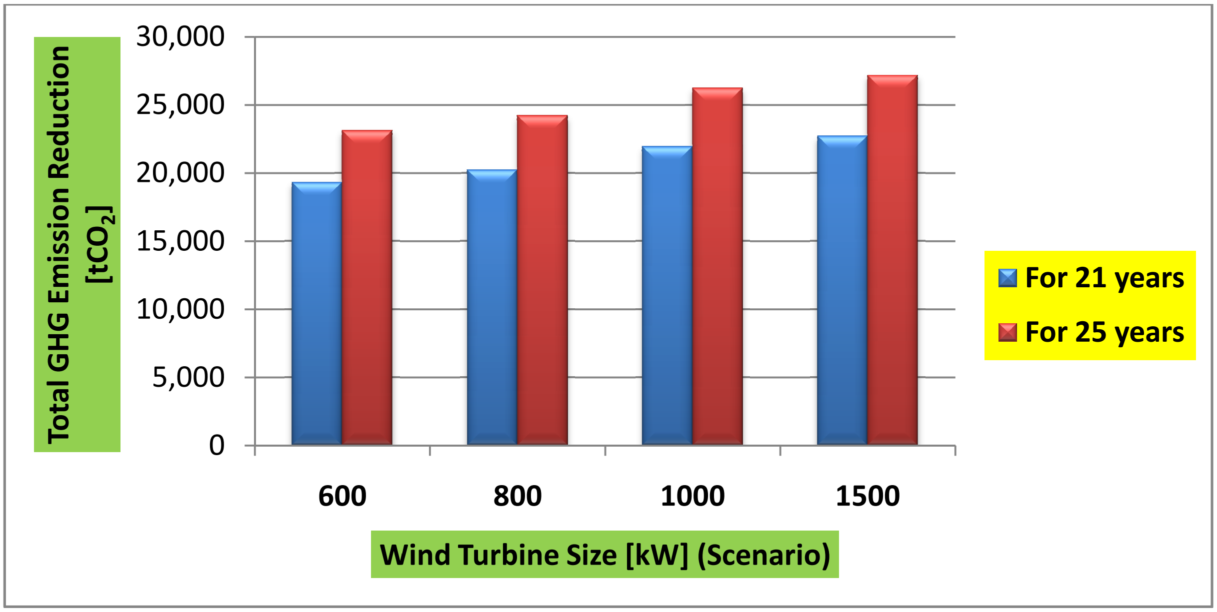


Chart 6.1: Total GHG Emission Reduction Comparison for All Scenarios

The total GHG emission reduction that occurred in the 21 years project operation period- crediting period- and project life time operation -25 years- are compared in the following chart. As can be seen from the chart, the 1500 kW turbine size scenario has the capacity to reduce more GHG emission than the other scenarios. Using 34 WECSs of 1500 kW rated power will result in a reduction in GHG of 22,719 tons in 21 years and 27,182 tons in its life time (25 years) from entering into the local atmosphere. Using 1000 kW, 800 kW and 600 kW turbine sizes will result in a reduction in GHG of 21,940, 20,238and 19,327 tons in 21 years operation and 26,250, 24,213 and 23,123 tons in life time operation respectively.

6.6 CER Revenues

The net annual and total revenues generated from CER sales in each scenario are summarized in Table 6.3. A higher amount of GHG emission reduction results a higher amount of CER revenue. The assumed CERs price for the CDM project is $6 /CER. When applying this CERs price to the scenario with the highest GHG emission reduction, it results in annual revenues of $6,086and $6,696 for the first and the remaining crediting period respectively. The expected additional cash-flow to be generated through the application of CDM during the three crediting periods, for this scenario, is $136,346.

Table 6.3: Net Revenues Generated from CER Sales for All Scenarios

Wind Turbine Size Scenario [kW]	Annual Revenues from CER sales [USD/yr]		Total CER Revenues (21 years) [USD]
	Year 1 to 7	Year 8 to 21	
600	5,177	5,694	115,955
800	5,421	5,964	121,443
1000	5,877	6,462	131,607
1500	6,086	6,696	136,346

For CDM projects, there is a transaction fee, 2% of the CERs generated, to be paid each year to the crediting agency and/ or the host country. But projects in least developed countries are exempt from this part of the levy in order to promote the equitable distribution of projects [1, 85]. So, the given values in Table 6.3 are free from transactions costs.

6.6.1 Impact of CERs on Project Viability

The net financial gain derived from the sale of CERs is the difference between the project CER value and the transaction costs. There are three elements that influence the net impact of CERs on project profitability: value of CERs (low CER value implies low net benefits), overall transaction costs (high transaction costs yield low nit benefits), and up-front transaction costs (high upfront payments could also result in low benefits) [10, 40].

The application of subsides on capital finance to the up-front and CDM periodic costs are considered in order to evaluate the impacts of CERs on IRRs and NPV of all scenarios. The impact of CERs on the IRRs and NPV for all wind farm scenarios are elaborated below.

- **Impact on IRR:**

Table 6.4 presents the impacts of carbon financing on IRRs to the proposed 51 MW wind farm project in Nazareth. Taking CER price of $6, for all wind farm scenarios, the IRR value increases by not more than **0.1%** (very small percentage point increase). This shows that the impact of CERs on the wind power project IRR is very small.

Table 6.4: The IRR with and without CDM for All Wind Farm Scenarios

Wind Turbine Size Scenario [kW]	**IRR [%]**		**Change in IRR [%]**
	Without CDM	**With CDM**	
600	13.8	13.9	**0.1**
800	17.9	17.9	**< 0.1**
1000	23.3	23.4	**0.1**
1500	31.0	31.1	**0.1**

- **Impact on NPV:**

When calculating the net present value of the total emission reduction potential, it is approximately **0.234%** of the total investment costs of the wind park. Thus, CDM does not indicate significant improvement in project performance through the effect of the relevant CDM cash flows.

Chapter 7

Sensitivity and Risk Analysis

The RETScreen software is capable of performing a Sensitivity and Risk analysis of wind energy projects. Using this model, it is possible to estimate the sensitivity of important financial indicators in relation to key technical and financial parameters. The Sensitivity Analysis and Risk Analysis sections provide information on the relationship between the key parameters and the important financial indicators. This shows the parameters which have the greatest impact on the financial indicators.

The purpose of the sensitivity testing is to establish which project parameters have the potential to alter the financial feasibility of the project by the greatest amount. By systematically altering individual parameters and recording the influence on the project evaluation criteria, those parameters with the greatest potential to cause the economics of the project to deviate from its expected value can be isolated. This provides a transparent overview of the project's risk profile, assists project planning, and helps prepare risk mitigation strategies [17, 244].

The risk analysis helps to assess if the variability of the financial indicator is acceptable, or not, by looking at the distribution of the possible outcomes. An unacceptable variability will be an indication of a need to put more effort into reducing the uncertainty associated with the input parameters that were identified as having the greatest impact on the financial indicator [1, 89].

7.1 Approach

Both the Sensitivity and Risk analyses are done only for Scenario IV, which is the 1500 kW Turbine size scenario that was evaluated as the best in the financial feasibility analysis. The analyses will be performed on the project Internal Rate of Return – IRR.

A sensitivity range of the order of 20% is assumed for the sensitivity analysis. This term defines the maximum percentage variation that will be applied to all the key parameters in the sensitivity analysis result tables. The assumption was taken based on the RETScreen case studies. Each parameter is varied by the following fraction of the sensitivity range: -1, -1/2, 0, 1/2 and 1.

A threshold value of 15% IRR is assumed for the sensitivity analysis. A result below this threshold value indicates that the proposed project is financially unviable and they appear as orange cells in the sensitivity analysis result tables.

A level of risk of 10% is assumed in this study, which is typical value for standard risk analysis [1, 94]. The level of risk input is used to establish a confidence interval (defined by maximum and minimum limits) within which the financial indicator is expected to fall. The level of risk represents the probability that the financial indicator will fall outside this confidence interval.

7.2 Sensitivity Variables

The sensitivity analysis was conducted for the following parameters:

- Avoided cost of energy
- RE Delivered
- Initial costs
- Annual costs
- Debt ratio
- Debt interest rate
- Debt term
- Net GHG emission reduction – 21 yrs

7.3 Results: Sensitivity Analysis

In this section the results of the sensitivity analysis of different parameters for the project IRR is presented. Each table shows what happens to the IRR when two key parameters are varied by the indicated percentage. As explained earlier parameters are varied using the following fraction of sensitivity range: -1, -1/2, 0, 1/2, 1.

Results which indicate an unviable project, i.e. those with IRR value less than 15%, are represented by orange cells in the sensitivity analysis result table. As can be observed from the following tables, the variables which resulted the greater potential effect on project IRR are RE delivered, avoided cost of energy, initial costs and annual costs.

When the RE delivered and the avoided costs of energy are varied by -20%, it results the greatest potential impact on project IRR, which is 3.6% (see Table 7.1). Whereas keeping one of the two parameters while varying the other by -10% results an IRR value of the order of 8.0%. Likewise an IRR value of 12.9% is resulted for 0% variation. Varying the two parameters by -10% results in an IRR value of 13.6%.

Table 7.1: Sensitivity Analysis of RE Delivered with Avoided Cost of Energy for IRR

RE Delivered [kWh]		**Avoided Cost of Energy ($/kWh)**				
		0.056 -20%	0.063 -10%	**0.070** 0%	0.077 10%	0.084 20%
121,497	-20%	3.6%	8.0%	12.9%	19.0%	26.6%
136,685	-10%	8.0%	13.6%	20.7%	29.9%	41.1%
151,872	0%	12.9%	20.7%	**31.1**%	43.8%	57.8%
167,059	10%	19.0%	29.9%	43.8%	59.2%	75.3%
182,246	20%	26.6%	41.1%	57.8%	75.3%	93.1%

As can be observed from Table 7.2, an IRR value of the order of 7.6% is obtained when the initial costs and the avoided cost of energy are varied by 20% and -20%, respectively. That indicates a lesser potential impact on the project IRR compared to what resulted in Table 7.1.

An IRR value of the order of 9.9, 12.9 and 12.7% are also resulted as it is shown in the orange cells of table 7.2. The IRR values indicated in the orange color represents financially unviable project. Because these values are less than the assumed 15% threshold value for the sensitivity analysis.

Table 7.2: Sensitivity Analysis of Initial Costs with Avoided Cost of Energy for IRR

Initial Costs [$]		**Avoided Cost of Energy ($/kWh)**				
		0.056 -20%	0.063 -10%	**0.070** 0%	0.077 10%	0.084 20%
56,990,326	-20%	23.4%	37.7%	54.8%	72.9%	91.5%
64,114,117	-10%	17.1%	27.5%	41.0%	56.5%	72.6%
71,237,908	0%	12.9%	20.7%	**31.1**%	43.8%	57.8%
78,361,698	10%	9.9%	16.1%	24.0%	34.2%	46.1
85,485,489	20%	7.6%	12.7%	19.0%	27.0%	36.9%

Similarly, the result in Table 7.3 also shows that the variation of the annual costs and the avoided cost of energy can affect the project IRR. Keeping the avoided cost of energy variation at -20% while varying the annual costs by -10, 0, 10 and 20%, an IRR value of the order of 14.9, 12.9, 11.1 and 9.3% have resulted, respectively.

Table 7.3: Sensitivity Analysis of Annual Costs with Avoided Cost of Energy for IRR

Annual Costs [$]		**Avoided Cost of Energy ($/kWh)**				
		0.056 -20%	0.063 -10%	**0.070** 0%	0.077 10%	0.084 20%
2,420,533	-20%	17.1%	26.3%	38.1%	51.7%	66.0%
2,723,100	-10%	14.9%	23.4%	34.5%	47.7%	61.9%
3,025,666	0%	12.9%	20.7%	**31.1**%	43.8%	57.8%
3,328,233	10%	11.1%	18.2%	27.8%	40.0%	53.7%
3,630,799	20%	9.3%	16.0%	24.8%	36.3%	49.7%

The resulted IRR values in Table 7.4 and Table 7.5 show that the deviation of the debt interest rate, debt ratio and debt term from there expected value have a very less potential impact on project IRR. This indicates that these parameters are insignificant in determining the project IRR.

Table 7.4: Sensitivity Analysis of Debt Interest Rate with Debt Ratio for IRR

Debt Interest Rate [%]		**Debt Ratio [%]**				
		72.0%	81.0%	**90%**	99.0%	N/A
		-20%	-10%	0%	10%	20%
4.0	-20%	20.7%	25.0%	35.3%	209.9%	
4.5	-10%	20.1%	24.0%	33.2%	180.2%	
5.0	0%	19.5%	23.0%	**31.1**%	150.7%	
5.5	10%	18.9%	22.0%	29.0%	121.7%	
6.0	20%	18.3%	21.1%	27.1%	94.2%	

Table 7.5: Sensitivity Analysis of Debt Interest Rate with Debt Term for IRR

Debt Interest Rate [%]		**Debt Term [yr]**				
		12.0	13.5	**15.0**	16.5	18.0
		-20%	-10%	0%	10%	20%
4.0	-20%	26.9%	31.2%	35.3%	39.6%	43.3%
4.5	-10%	25.4%	29.4%	33.2%	37.2%	40.7%
5.0	0%	24.1%	27.7%	**31.1**%	34.8%	38.2%
5.5	10%	22.8%	26.0%	29.0%	32.5%	35.7%
6.0	20%	21.6%	24.5%	27.1%	30.3%	33.2%

As Table 7.6 shows, the project IRR is the most immune against fluctuation in GHG emission reduction credit. For any variation in the parameters, the resulted IRR value is the same as the original project IRR value, i.e. 31.1%.

Table 7.6: Sensitivity Analysis of GHG Emission Reduction Credit for IRR

Net GHG Emission Reduction - 21 yrs [tCO$_2$]		**GHG emission reduction credit [$\$/\text{tCO}_2$]**				
		4.8	5.4	**6.0**	6.6	7.2
		-20%	-10%	0%	10%	20%
18,176	-20%	31.0%	31.0%	31.0%	31.0%	31.1%
20,448	-10%	31.0%	31.0%	31.0%	31.1%	31.1%
22,719	0%	31.0%	31.0%	**31.1%**	31.1%	31.1%
24,991	10%	31.0%	31.1%	31.1%	31.1%	31.1%
25,660	20%	31.1%	31.1%	31.1%	31.1%	31.1%

Therefore the main important parameters that determine the project IRR to a greater extent are avoided cost of energy, RE delivered, initial costs and annual costs. The remaining parameters, i.e. debt interest rate, debt ratio, debt term and GHG emission reduction credit would have a less dramatic impact on the project IRR.

7.4 Risk Parameters

In order to evaluate the variability of the IRR, each risk parameter will be allowed to vary in a particular specified range. The range is a percentage corresponding to the uncertainty associated with the estimated risk parameter value. The higher the percentage, the greater is the uncertainty. The range determines the limits of the interval of possible values that the risk parameter could take. If the value for the parameter is known exactly, i.e. no uncertainty, a range of 0% can be assumed. The assumed range values for the risk parameters are summarized in the following table.

Table 7.7: Range Values for the Risk Parameters

Risk Parameter	Unit	Value	Range (+/-)
Avoided Cost of Energy	\$/kWh	0.07	**15%**
RE Delivered	MWh	151,872	**10%**
Initial Costs	\$	71,237,908	**15%**
Annual Costs	\$	3,025,666	**15%**
Debt Ratio	%	90.0	**5%**
Debt Interest Rate	%	5.0	**30%**
Debt Term	Yr	15	**0%**
GHG Emission Reduction Credit	$\$/tCO_2$	6.0	**20%**

The risk parameters are presented in detail in the following section.

7.4.1 Avoided Cost of Energy

The avoided cost of energy range of the order of 15% is assumed for the risk analysis. The range is a percentage corresponding to the uncertainty associated with the estimated avoided cost of energy value. The higher the percentage, the greater is the uncertainty. The range specified for the avoided cost of energy must be between 0 and 50%. The range determines the limits of the interval of possible values that the avoided cost of energy could take.

Since 0.07 $/kWh is the estimated value, the risk analysis will consider this value as being the most probable and the minimum and maximum values as being the least probable, based on a normal distribution.

7.4.2 RE Delivered

A 10% range value is assumed for the renewable energy delivered. The range is a percentage corresponding to the uncertainty associated with the estimated renewable energy delivered value.

The higher the percentage, the greater is the uncertainty. The range specified for the renewable energy delivered must be between 0 and 50%. The range determines the limits of the interval of possible values that the renewable energy delivered could take.

Since 151,872 MWh is the estimated value, the risk analysis will consider this value as being the most probable and the minimum and maximum values as being the least probable, based on a normal distribution.

7.4.3 Initial Costs

A range value of the order of 15% is assumed for the initial costs. The range is a percentage corresponding to the uncertainty associated with the estimated initial costs value. The higher the percentage, the greater is the uncertainty. The range specified for the initial costs must be between 0 and 50%. The range determines the limits of the interval of possible values that the initial costs could take.

Since $71,237,908 is the estimated value, the risk analysis will consider this value as being the most probable and the minimum and maximum values as being the least probable, based on a normal distribution.

7.4.4 Annual Costs

A range value of the order of 15% is assumed for the annual costs. The range is a percentage corresponding to the uncertainty associated with the estimated annual costs value. The higher the percentage, the greater is the uncertainty. The range specified for the annual costs must be between 0 and 50%. The range determines the limits of the interval of possible values that the annual costs could take.

Since $3,025,666 is the estimated value, the risk analysis will consider this value as being the most probable and the minimum and maximum values as being the least probable, based on a normal distribution.

7.4.5 Debt Ratio

A range value of the order of 5% is assumed for the debt ratio. The range is a percentage corresponding to the uncertainty associated with the estimated debt ratio value. The higher the percentage, the greater is the uncertainty. The range specified for the debt ratio must be a percentage value between 0% and the lowest percentage such that the debt ratio will always fall between 0 and 100%. The range determines the limits of the interval of possible values that the debt ratio could take.

Since 90% is the estimated value, the risk analysis will consider this value as being the most probable and the minimum and maximum values as being the least probable, based on a normal distribution.

7.4.6 Debt Interest Rate

A range value of the order of 30% is assumed for the debt interest rate. The range is a percentage corresponding to the uncertainty associated with the estimated debt interest rate value. The higher the percentage, the greater is the uncertainty. The range specified for the debt interest rate must be between 0 and 50%. The range determines the limits of the interval of possible values that the debt interest rate could take.

Since 10% is the estimated value, the risk analysis will consider this value as being the most probable and the minimum and maximum values as being the least probable, based on a normal distribution.

7.4.7 Debt Term

The range is a percentage corresponding to the uncertainty associated with the estimated debt term value. The higher the percentage, the greater is the uncertainty. The range specified for the debt term must be a percentage value between 0% and the lowest percentage such that the debt term will always fall between 1 year and the project life. The range determines the limits of the interval of possible values that the debt term could take.

The debt term is known exactly, that is no uncertainty. So 0% range value is assumed for the debt term.

7.4.8 GHG Emission Reduction Credit

A 20% range value is assumed for the GHG Emission Reduction Credit. The range is a percentage corresponding to the uncertainty associated with the estimated GHG Emission Reduction Credit value. The higher the percentage, the greater is the uncertainty. The range specified for the GHG Emission Reduction Credit must be between 0 and 50%. The range determines the limits of the interval of possible values that the GHG Emission Reduction Credit could take.

Since 6 $\$/tCO_2$ is the estimated value, the risk analysis will consider this value as being the most probable and the minimum and maximum values as being the least probable, based on a normal distribution.

7.5 Results: Risk Analysis

The risk analysis is calculated based on the input parameter ranges given in Table 7.7. The risk analysis performed using a Monte Carlo simulation that includes 500 possible combinations of input variables in 500 values of IRR [1, 89]. The impact graph, the median, the minimum and maximum confidence levels, and the distribution graph are calculated using these results. The risk analysis results are elaborated as follows.

7.5.1 Impact Graph

The impact graph shows the relative contribution of the uncertainty in each key parameter to the variability of the IRR. The X axis at the bottom of the graph does not have any units, but rather presents a relative indication of the strength of the contribution of each parameter [1, 93].

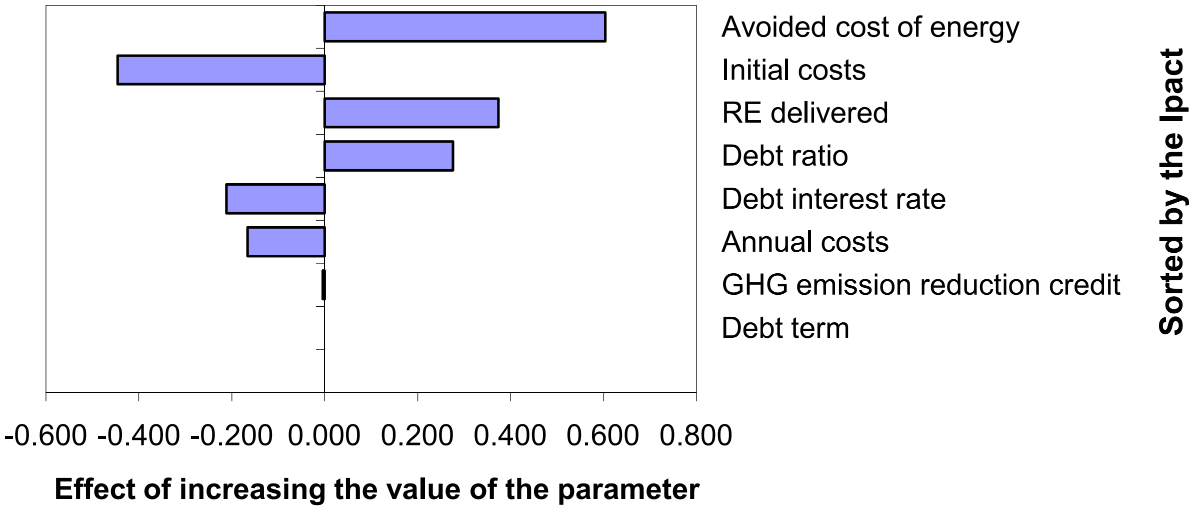


Fig. 7.1: Impact graph

As Fig. 7.1 indicates, the avoided cost of energy takes the first place in having longest horizontal bar. This indicates that the avoided cost of energy has the greatest impact on the variability of the project IRR, followed by initial costs, RE delivered and debt ratio. The GHG emission reduction credit has the least impact on the project IRR.

The risk parameters are sorted according to the degree of their impact on the IRR. The parameters at the top (Y axis), such as the avoided cost of energy and the initial costs, contribute the most to the variability of the IRR. Whereas the parameters at the bottom, like debt term and GHG emission reduction credit, contribute the least.

The direction of the horizontal bar (positive or negative) provides an indication of the relationship between the risk parameter and the IRR. As Fig. 7.1 shows, there is a positive relationship between the avoided cost of energy and the IRR. This is because an increase in the value of the avoided cost of energy results in an increase in the value of the project IRR. In contrast there is a negative relationship between the initial costs and the IRR, which means an increase in the value of initial costs results in a decrease in the value of the project IRR.

7.5.2 Distribution Graph

This histogram provides a distribution of the possible values for the IRR resulting from the Monte Carlo simulation. The height of each bar represents the frequency (%) of values that fall in the range defined by the width of each bar. The value corresponding to the middle of each range is plotted on the X axis.

As Fig. 7.2 shows, there is a very less possibility that the IRR value falls below 14.2% and above 48.6%. The greater possibility takes place between 21.9% and 37.1% values. Looking at the distribution of IRR, its variability is acceptable.

7.5.3 Bar Graph

The bar graph summarizes the maximum and minimum IRR values that can be expected according to the defined level of risk.

The "Minimum within level of confidence" is the lower limit of the confidence interval within which the IRR likely falls. As it is clearly indicated in fig. 7.3, the expected "minimum within level of confidence" value is 17.9%. That means only 5% (half the level of risk) of the possible IRR values are lower than 17.9%.

The calculated median value is 30.4%. As it is expected, the resulted median value is close to the original IRR value calculated in the financial summary, which is 31.1%. A 90% of the possible IRR values will be expected to take place between 17.9 and 48.3%.

The "Maximum within level of confidence" is the upper limit of the confidence interval within which the IRR likely falls. It is the percentile of the distribution of the IRR corresponding to 100% minus half the level of risk (5%). As the following figure shows, the expected "Maximum within level of confidence" value is 48.3%. That means 95% of the possible IRR values are lower than 48.3%.

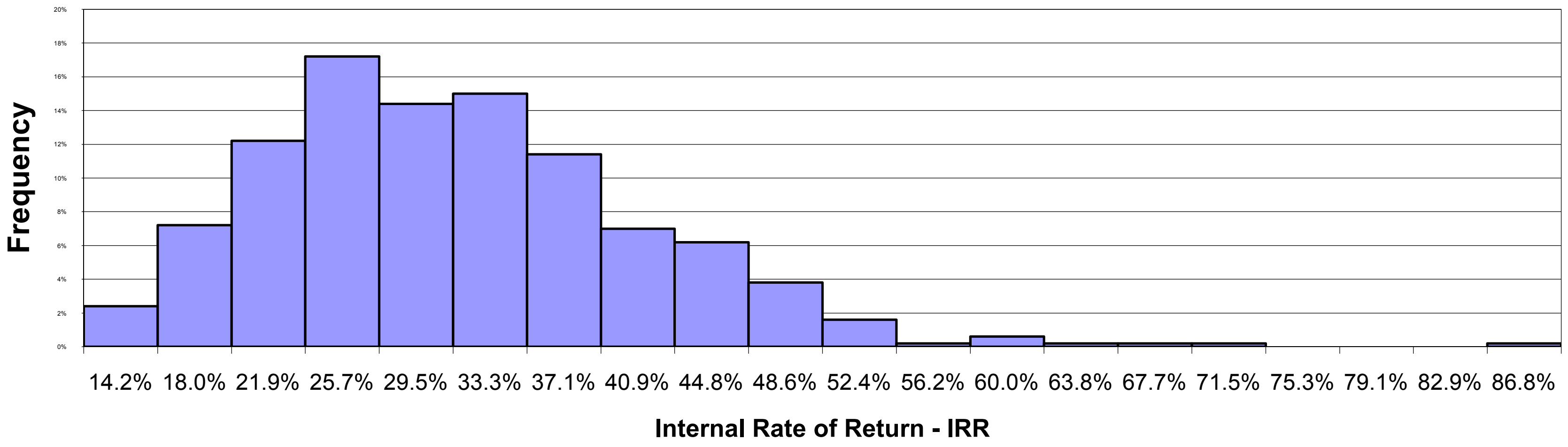


Fig. 7.2: Distribution of Internal Rate of Return – IRR, from RETScreen Model

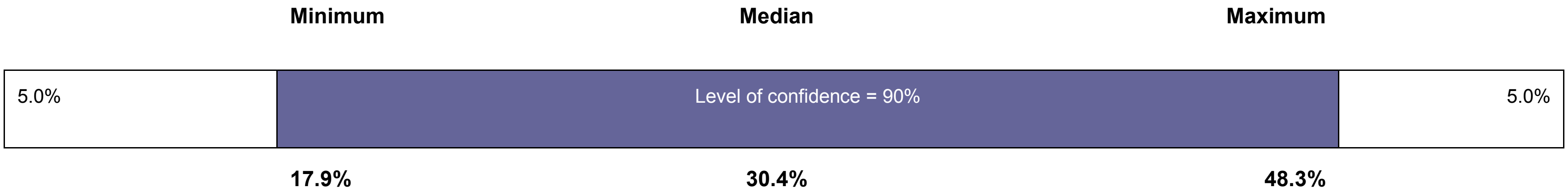


Fig. 7.3: Bar Graph, from RETScreen Model

Chapter 8

Conclusion and Recommendation

8.1 Conclusion

- The estimated energy yield using different wind farm scenarios is summarized in the following table. Scenario IV, with its net annual energy production (RE delivered) of ***151,872 MWh***, specific energy yield of ***1306 kWh/m²*** and wind plant capacity factor of ***34%***, is selected to be the best wind farm scenario for Nazareth site.

Table 8.1: Summary of the Main Estimation Results for the Different Wind Farm Scenarios

Scenario	**Scenario I**	**Scenario II**	**Scenario III**	**Scenario IV**
Turbine capacity [kW]	600	800	1000	1500
No of Turbines	85	64	51	34
Installed capacity [kW]	51,000	51,000	51,000	51,000
Hub height [m]	46	50	60	65
Rotor diameter [m]	43	52	54	66
Swept area [m^2]	1,452	2,124	2,290	3,421
Gross energy production [MWh/y]	141,580	148,182	160,646	166,352
Total losses [%]	9.0	9.0	9.0	9.0
RE delivered [MWh/y]	129,256	135,283	146,663	151,872
Specific yield [kWh/m^2]	1047	995	1256	1306
Capacity factor [%]	29	30	33	34

- The financial feasibility study is performed in terms of internal rate of return (IRR), net present value (NPV), annual life cycle saving (ALCS), year to positive cash flow (YPCF), benefit to cost ratio (B-C) and debt service coverage (DSC). For all scenarios, the calculated IRR values are greater than the economic discount rate. Similarly a positive NPV is obtained for all scenarios in all discount rates. Scenario IV (1500 kW wind turbine size) has the best ***IRR** and **NPV*** values of ***31.1%** and **$28,244,174,*** respectively compared to the remaining wind farm scenarios. Also ***ALCS** of **$3,111,606, YPCF** of **3.9 years, BC ratio** of **4.96***, are obtained for this scenario, which are best values compared to the remaining scenarios. Under these conditions, the Nazareth wind farm project is financially feasible for all wind farm scenarios.

  However, the only scenario that meets the minimum DSCR required by the lender is Scenario IV. Using this scenario, a DSCR of ***1.26*** is obtained which is sufficient enough. The obtained DSCRs for the remaining wind farm scenarios are ***below 1.20***, which is the minimum lender requirement. Therefore, ***only Scenario IV is eligible*** in order to get the required loan for the wind project from the lender.

  Compared to the Diesel power plants operating in Ethiopia, the resulted economic energy production costs of the Nazareth wind farm for all scenarios are very low. A best economic energy production costs of the order of ***0.0528 $/kWh*** is obtained for the scenario with 1500 kW turbine size, that is ***Scenario IV***.

- According to the CDM assessment done in the above sections, the Nazareth wind farm project can be registered as CDM activity. Among other conditions settled by the UNFCCC, its implementation can allow to reduce emissions below those emissions that would have occurred in the absence of the wind farm.

  The Ethiopian grid system is highly dominated by hydropower, which is expressed in the very low emission factor of ***0.0063*** tCO_2/MWh. This emission factor results a total emission reduction potential of ***22,719*** tCO_2 in the three crediting periods. The emission reductions generated by the wind park is very low compared to similar sized wind park projects in other countries, which follows a less amount of CER revenue. The expected additional cash-flow to be generated through the application of CDM during the three crediting periods is ***$136,346***.

Compared to the total investment cost of the wind farm, the additional cash-flow generated by the CDM does not indicate significant improvement in project performance. Though the application of subsides on capital finance to the up-front and CDM periodic costs are considered, the registration of the project is ***financially hardly feasible***.

8.2 Recommendation

As the output of this thesis clearly indicates, using RETScreen model for the assessment of wind energy projects can give a complete result, which is normally obtained by using more than one simulation model. Additionally RETScreen:

- Simplifies the preliminary evaluation, in that it requires little user input and it calculates key technical and financial viability indicators automatically,
- Costs 1/10th the amount of other assessment methods,
- Allows objective comparisons that follow standardized procedures,
- Increases potential for successful clean energy project implementation.

it is, therefore, recommended that RETScreen model should be used for the assessment of the future wind energy projects to be installed in Ethiopia to gain the above benefits from the model.

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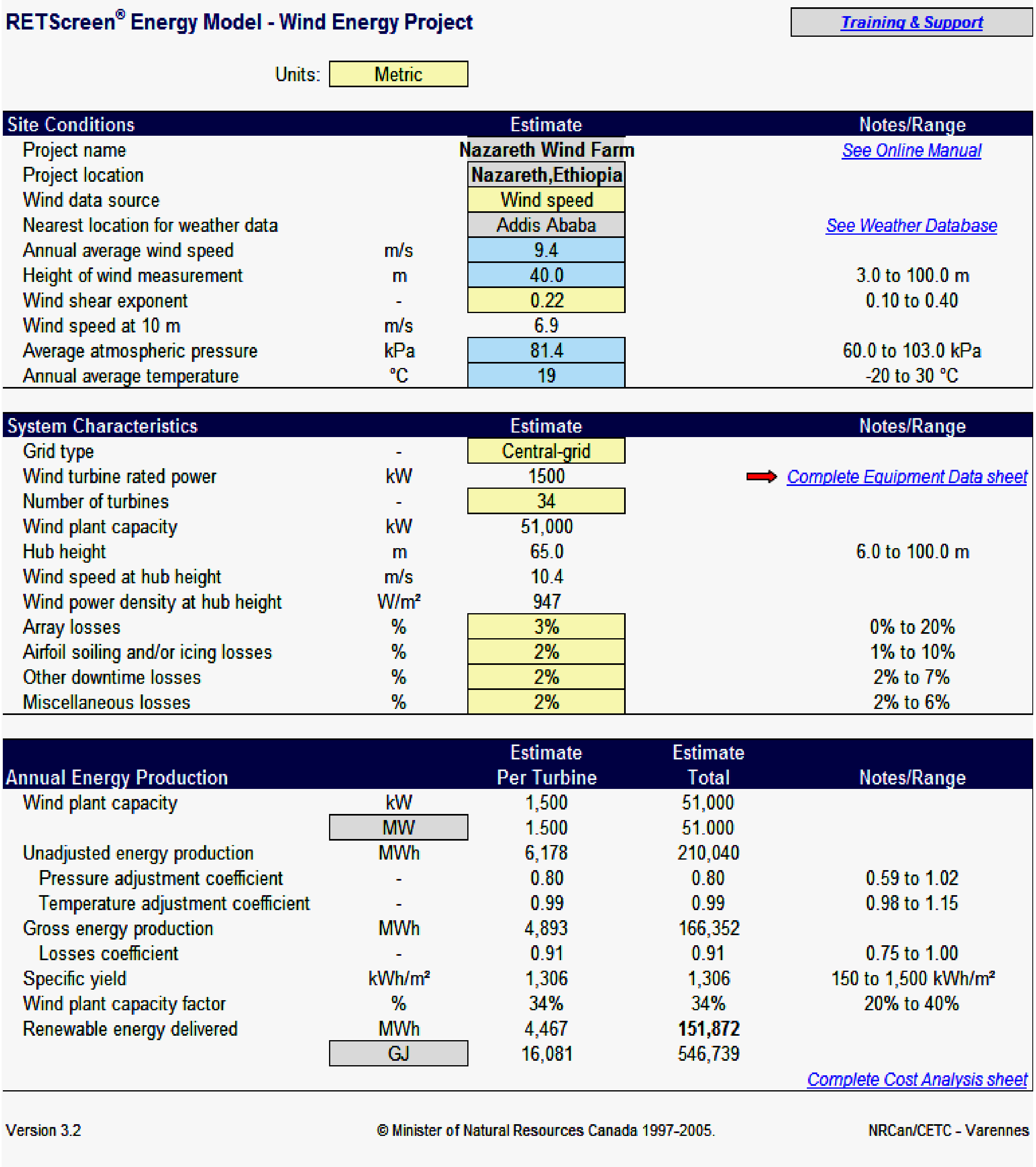
Annex A

Annex A-1: RETScreen model worksheet summary for the best scenario, 1500 kW machine



RETScreen® Energy Model - Wind Energy Project

Training & Support

Units: Metric

Site Conditions		Estimate	Notes/Range
Project name		**Nazareth Wind Farm**	See Online Manual
Project location		**Nazareth,Ethiopia**	
Wind data source		Wind speed	
Nearest location for weather data		Addis Ababa	See Weather Database
Annual average wind speed	m/s	9.4	
Height of wind measurement	m	40.0	3.0 to 100.0 m
Wind shear exponent	-	0.22	0.10 to 0.40
Wind speed at 10 m	m/s	6.9	
Average atmospheric pressure	kPa	81.4	60.0 to 103.0 kPa
Annual average temperature	°C	19	-20 to 30 °C

System Characteristics		Estimate	Notes/Range
Grid type	-	Central-grid	
Wind turbine rated power	kW	1500	➡ Complete Equipment Data sheet
Number of turbines	-	34	
Wind plant capacity	kW	51,000	
Hub height	m	65.0	6.0 to 100.0 m
Wind speed at hub height	m/s	10.4	
Wind power density at hub height	W/m²	947	
Array losses	%	3%	0% to 20%
Airfoil soiling and/or icing losses	%	2%	1% to 10%
Other downtime losses	%	2%	2% to 7%
Miscellaneous losses	%	2%	2% to 6%

Annual Energy Production		Estimate Per Turbine	Estimate Total	Notes/Range
Wind plant capacity	kW	1,500	51,000	
	MW	1.500	51.000	
Unadjusted energy production	MWh	6,178	210,040	
Pressure adjustment coefficient	-	0.80	0.80	0.59 to 1.02
Temperature adjustment coefficient	-	0.99	0.99	0.98 to 1.15
Gross energy production	MWh	4,893	166,352	
Losses coefficient	-	0.91	0.91	0.75 to 1.00
Specific yield	kWh/m²	1,306	1,306	150 to 1,500 kWh/m²
Wind plant capacity factor	%	34%	34%	20% to 40%
Renewable energy delivered	MWh	4,467	**151,872**	
	GJ	16,081	546,739	

Complete Cost Analysis sheet

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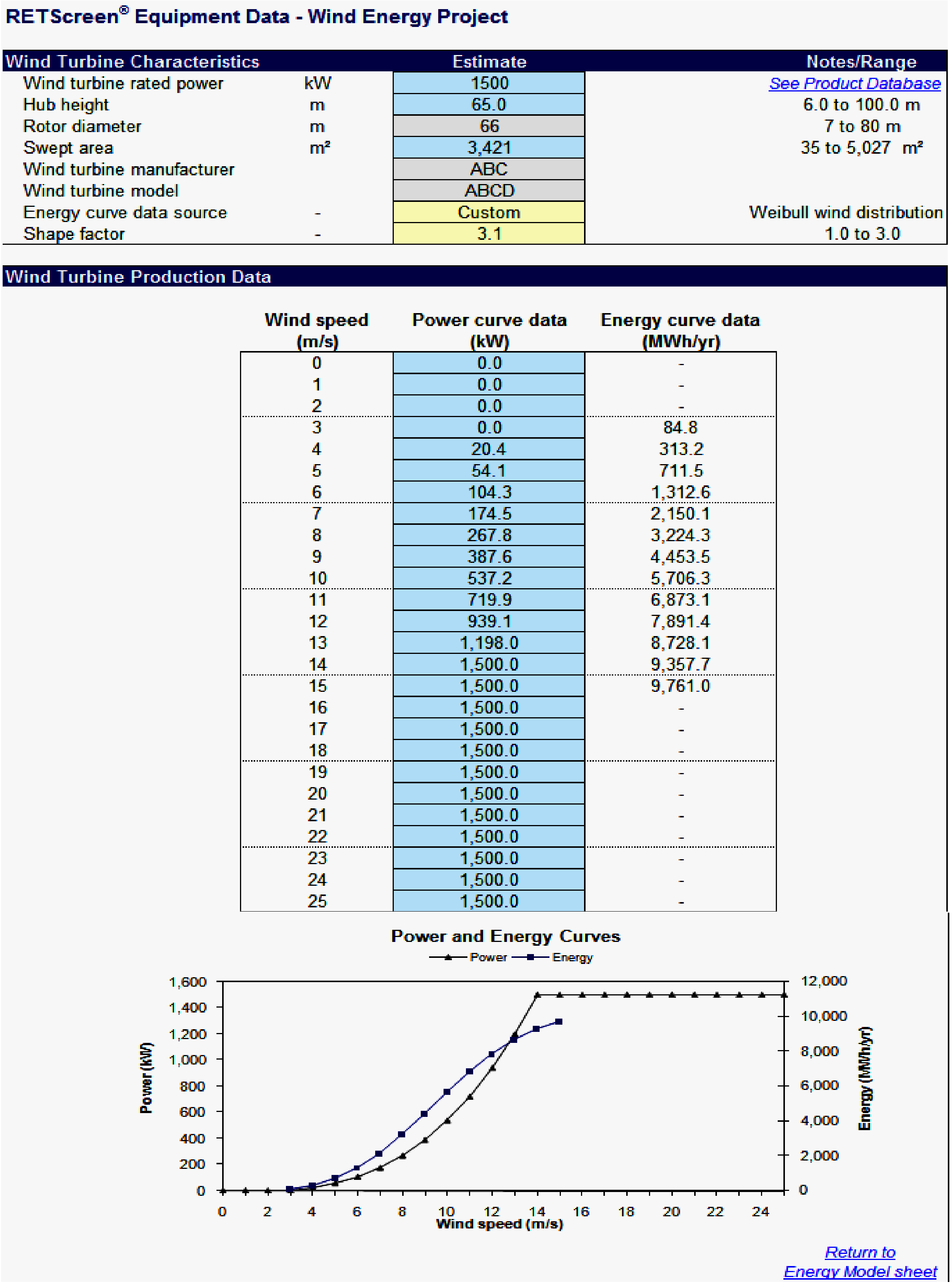


RETScreen® Equipment Data - Wind Energy Project

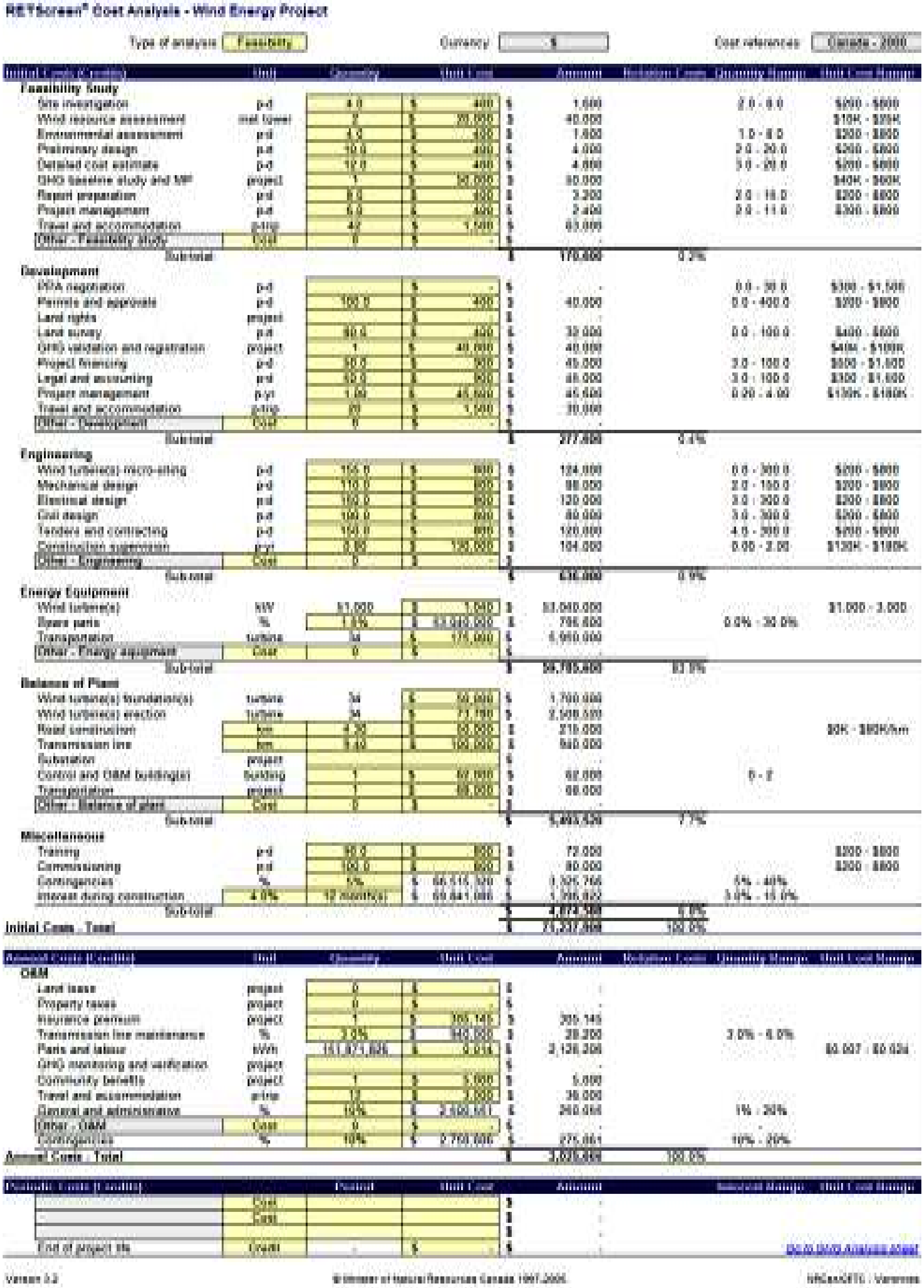
Wind Turbine Characteristics		Estimate	Notes/Range
Wind turbine rated power	kW	1500	*See Product Database*
Hub height	m	65.0	6.0 to 100.0 m
Rotor diameter	m	66	7 to 80 m
Swept area	m²	3,421	35 to 5,027 m²
Wind turbine manufacturer		ABC	
Wind turbine model		ABCD	
Energy curve data source	-	Custom	Weibull wind distribution
Shape factor	-	3.1	1.0 to 3.0

Wind Turbine Production Data

Wind speed (m/s)	Power curve data (kW)	Energy curve data (MWh/yr)
0	0.0	-
1	0.0	-
2	0.0	-
3	0.0	84.8
4	20.4	313.2
5	54.1	711.5
6	104.3	1,312.6
7	174.5	2,150.1
8	267.8	3,224.3
9	387.6	4,453.5
10	537.2	5,706.3
11	719.9	6,873.1
12	939.1	7,891.4
13	1,198.0	8,728.1
14	1,500.0	9,357.7
15	1,500.0	9,761.0
16	1,500.0	-
17	1,500.0	-
18	1,500.0	-
19	1,500.0	-
20	1,500.0	-
21	1,500.0	-
22	1,500.0	-
23	1,500.0	-
24	1,500.0	-
25	1,500.0	-

Power and Energy Curves

Return to Energy Model sheet



RETScreen® Cost Analysis - Wind Energy Project

Type of analysis: Feasibility | Currency: $ | Cost references: Canada - 2000

Initial Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Relative Costs	Quantity Range	Unit Cost Range
Feasibility Study							
Site investigation	p-d	4.0	$ 400	$ 1,600		2.0 - 8.0	$200 - $800
Wind resource assessment	met tower	2	$ 20,000	$ 40,000			$10K - $20K
Environmental assessment	p-d	4.0	$ 400	$ 1,600		1.0 - 8.0	$200 - $800
Preliminary design	p-d	10.0	$ 400	$ 4,000		2.0 - 20.0	$200 - $800
Detailed cost estimate	p-d	10.0	$ 400	$ 4,000		3.0 - 20.0	$200 - $800
GHG baseline study and MP	project	1	$ 50,000	$ 50,000			$40K - $60K
Report preparation	p-d	8.0	$ 400	$ 3,200		2.0 - 16.0	$200 - $800
Project management	p-d	6.0	$ 400	$ 2,400		2.0 - 11.0	$200 - $800
Travel and accommodation	p-trip	42	$ 1,500	$ 63,000			
Other - Feasibility study	Cost	0	$ -	$ -			
Sub-total				$ 170,000	0.2%		
Development							
PPA negotiation	p-d		$ -	$ -		0.0 - 30.0	$300 - $1,500
Permits and approvals	p-d	100.0	$ 400	$ 40,000		0.0 - 400.0	$200 - $800
Land rights	project		$ -	$ -			
Land survey	p-d	80.0	$ 400	$ 32,000		0.0 - 100.0	$400 - $800
GHG validation and registration	project	1	$ 40,000	$ 40,000			$40K - $100K
Project financing	p-d	50.0	$ 900	$ 45,000		3.0 - 100.0	$500 - $1,500
Legal and accounting	p-d	50.0	$ 900	$ 45,000		3.0 - 100.0	$300 - $1,500
Project management	p-yr	1.00	$ 45,000	$ 45,000		0.20 - 4.00	$130K - $180K
Travel and accommodation	p-trip	20	$ 1,500	$ 30,000			
Other - Development	Cost	0	$ -	$ -			
Sub-total				$ 277,000	0.4%		
Engineering							
Wind turbine(s) micro-siting	p-d	155.0	$ 800	$ 124,000		0.0 - 300.0	$200 - $800
Mechanical design	p-d	110.0	$ 800	$ 88,000		2.0 - 150.0	$200 - $800
Electrical design	p-d	150.0	$ 800	$ 120,000		3.0 - 300.0	$200 - $800
Civil design	p-d	100.0	$ 800	$ 80,000		3.0 - 300.0	$200 - $800
Tenders and contracting	p-d	150.0	$ 800	$ 120,000		4.0 - 300.0	$200 - $800
Construction supervision	p-yr	0.80	$ 130,000	$ 104,000		0.00 - 2.00	$130K - $180K
Other - Engineering	Cost	0	$ -	$ -			
Sub-total				$ 636,000	0.9%		
Energy Equipment							
Wind turbine(s)	kW	51,000	$ 1,040	$ 53,040,000			$1,000 - 3,000
Spare parts	%	1.5%	$ 53,040,000	$ 795,600		0.0% - 30.0%	
Transportation	turbine	34	$ 175,000	$ 5,950,000			
Other - Energy equipment	Cost	0	$ -	$ -			
Sub-total				$ 59,785,600	86.3%		
Balance of Plant							
Wind turbine(s) foundation(s)	turbine	34	$ 50,000	$ 1,700,000			
Wind turbine(s) erection	turbine	34	$ 73,780	$ 2,508,520			
Road construction	km	4.30	$ 50,000	$ 215,000			$0K - $80K/km
Transmission line	km	5.60	$ 100,000	$ 560,000			
Substation	project			$ -			
Control and O&M building(s)	building	1	$ 62,000	$ 62,000		0 - 2	
Transportation	project	1	$ 68,000	$ 68,000			
Other - Balance of plant	Cost	0	$ -	$ -			
Sub-total				$ 5,493,520	7.9%		
Miscellaneous							
Training	p-d	90.0	$ 800	$ 72,000			$200 - $800
Commissioning	p-d	100.0	$ 800	$ 80,000			$200 - $800
Contingencies	%	2%	$ 66,515,320	$ 1,326,766		1% - 40%	
Interest during construction	4.0%	12 month(s)	$ 69,841,086	$ 1,396,822		3.0% - 15.0%	
Sub-total				$ 2,875,588	4.2%		
Initial Costs - Total				$ 69,237,708	100.0%		

Annual Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Relative Costs	Quantity Range	Unit Cost Range
O&M							
Land lease	project	0	$ -	$ -			
Property taxes	project	0	$ -	$ -			
Insurance premium	project	1	$ 305,145	$ 305,145			
Transmission line maintenance	%	3.0%	$ 940,000	$ 28,200		3.0% - 6.0%	
Parts and labour	kWh	151,871,826	$ 0.014	$ 2,126,206			$0.007 - $0.024
GHG monitoring and verification	project			$ -			
Community benefits	project	1	$ 5,000	$ 5,000			
Travel and accommodation	p-trip	12	$ 3,000	$ 36,000			
General and administrative	%	10%	$ 2,500,551	$ 250,055		1% - 20%	
Other - O&M	Cost	0	$ -	$ -		-	
Contingencies	%	10%	$ 2,750,606	$ 275,061		10% - 20%	
Annual Costs - Total				$ 3,025,667	100.0%		

Periodic Costs (Credits)		Period	Unit Cost	Amount	Interval Range	Unit Cost Range
	Cost			$ -		
	Cost			$ -		
				$ -		
End of project life	Credit	-	$ -	$ -		

Go to GHG Analysis sheet

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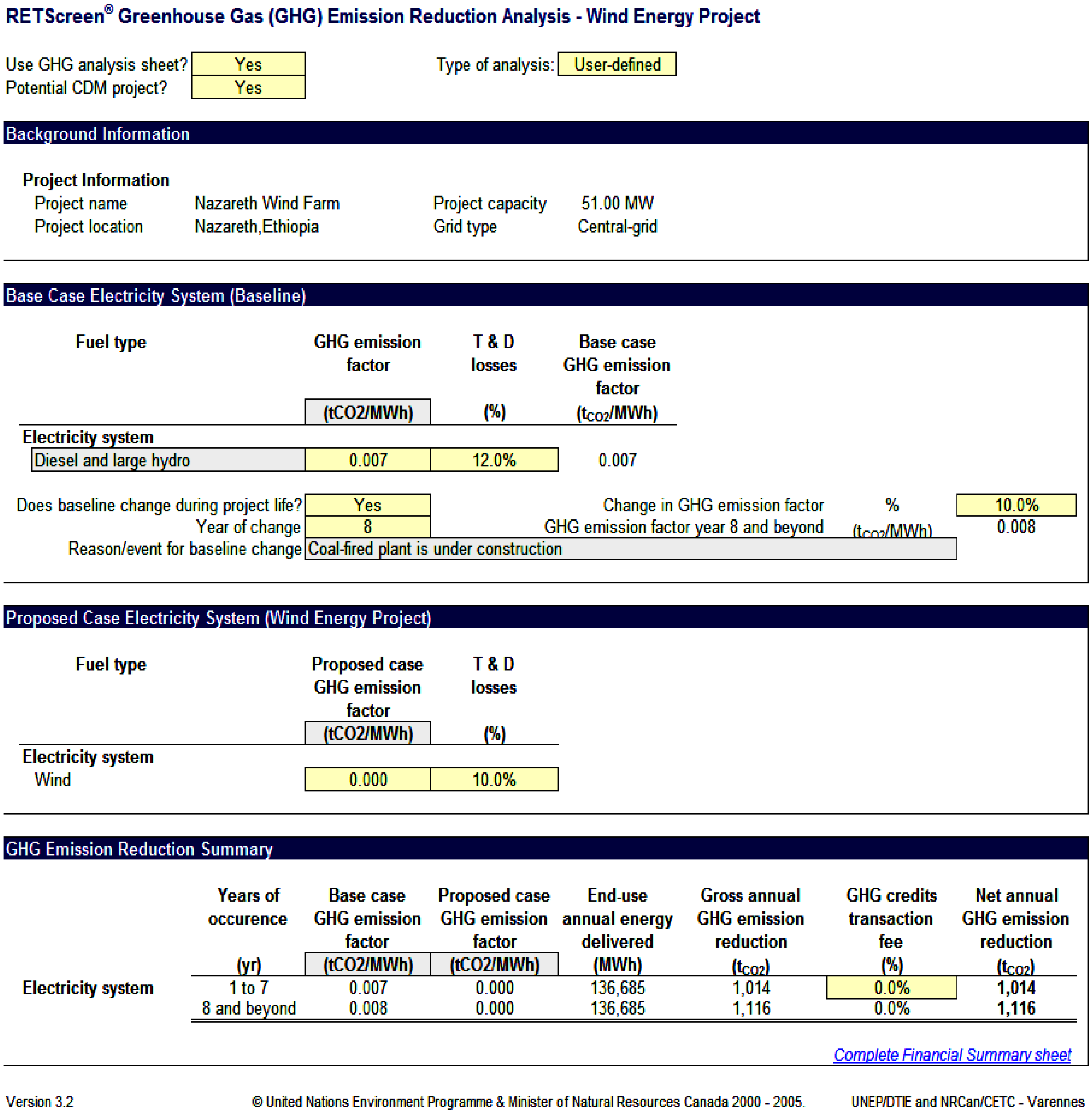

RETScreen® Greenhouse Gas (GHG) Emission Reduction Analysis - Wind Energy Project

Use GHG analysis sheet?	Yes	Type of analysis:	User-defined
Potential CDM project?	Yes		

Background Information

Project Information

Project name	Nazareth Wind Farm	Project capacity	51.00 MW
Project location	Nazareth,Ethiopia	Grid type	Central-grid

Base Case Electricity System (Baseline)

Fuel type	GHG emission factor (tCO2/MWh)	T & D losses (%)	Base case GHG emission factor (t_{CO2}/MWh)
Electricity system			
Diesel and large hydro	0.007	12.0%	0.007

Does baseline change during project life?	Yes	Change in GHG emission factor	%	10.0%
Year of change	8	GHG emission factor year 8 and beyond	(t_{CO2}/MWh)	0.008
Reason/event for baseline change	Coal-fired plant is under construction			

Proposed Case Electricity System (Wind Energy Project)

Fuel type	Proposed case GHG emission factor (tCO2/MWh)	T & D losses (%)
Electricity system		
Wind	0.000	10.0%

GHG Emission Reduction Summary

	Years of occurence (yr)	Base case GHG emission factor (tCO2/MWh)	Proposed case GHG emission factor (tCO2/MWh)	End-use annual energy delivered (MWh)	Gross annual GHG emission reduction (t_{CO2})	GHG credits transaction fee (%)	Net annual GHG emission reduction (t_{CO2})
Electricity system	1 to 7	0.007	0.000	136,685	1,014	0.0%	**1,014**
	8 and beyond	0.008	0.000	136,685	1,116	0.0%	**1,116**

Complete Financial Summary sheet

Version 3.2

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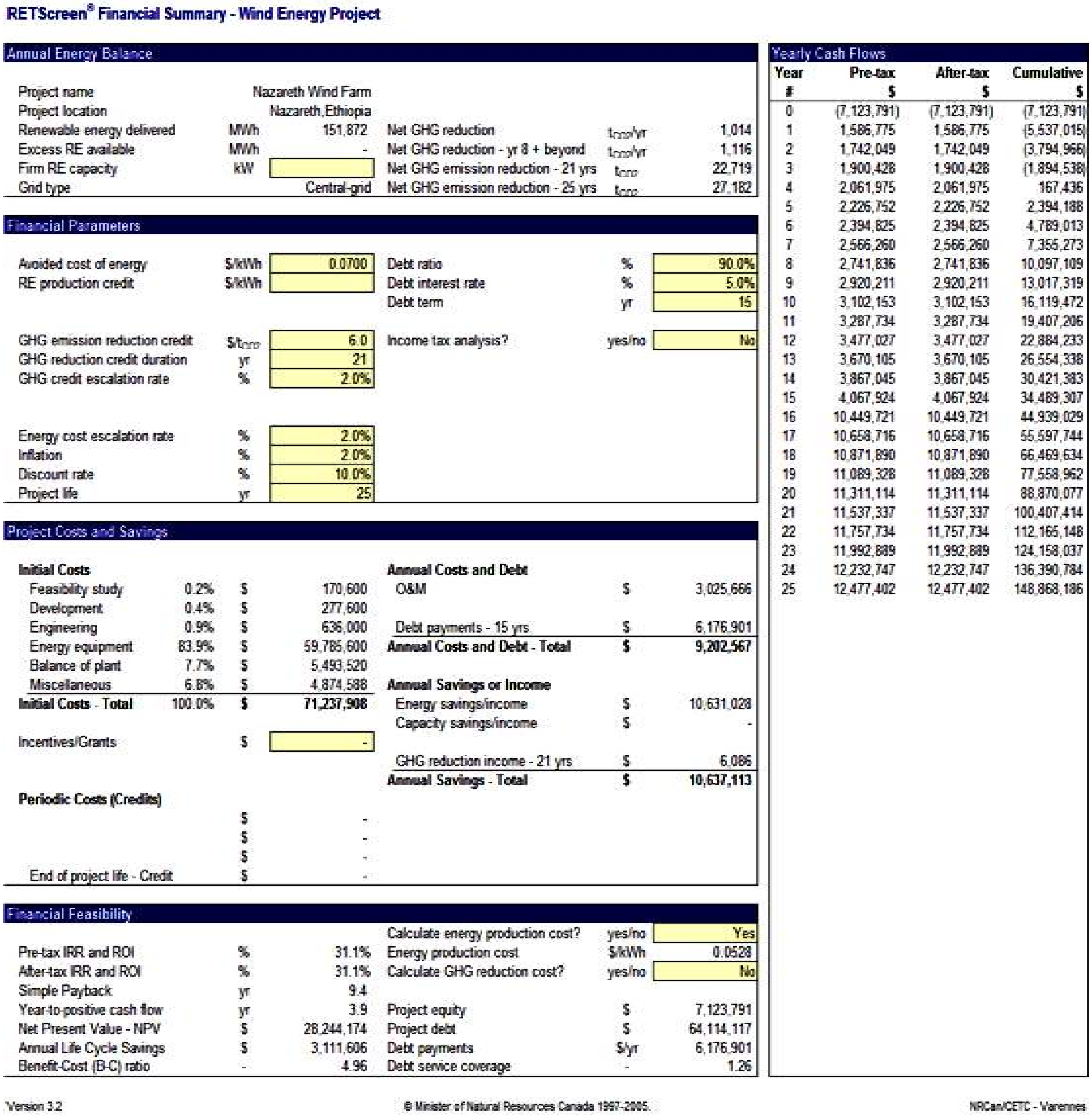

RETScreen® Financial Summary - Wind Energy Project

Annual Energy Balance

Project name		Nazareth Wind Farm			
Project location		Nazareth,Ethiopia			
Renewable energy delivered	MWh	151,872	Net GHG reduction	t_{CO2}/yr	1,014
Excess RE available	MWh	-	Net GHG reduction - yr 8 + beyond	t_{CO2}/yr	1,116
Firm RE capacity	kW		Net GHG emission reduction - 21 yrs	t_{CO2}	22,719
Grid type		Central-grid	Net GHG emission reduction - 25 yrs	t_{CO2}	27,182

Financial Parameters

Avoided cost of energy	$/kWh	0.0700	Debt ratio	%	90.0%
RE production credit	$/kWh		Debt interest rate	%	5.0%
			Debt term	yr	15
GHG emission reduction credit	$/$t_{CO2}$	6.0	Income tax analysis?	yes/no	No
GHG reduction credit duration	yr	21			
GHG credit escalation rate	%	2.0%			
Energy cost escalation rate	%	2.0%			
Inflation	%	2.0%			
Discount rate	%	10.0%			
Project life	yr	25			

Project Costs and Savings

Initial Costs				**Annual Costs and Debt**		
Feasibility study	0.2%	$	170,600	O&M	$	3,025,666
Development	0.4%	$	277,600			
Engineering	0.9%	$	636,000	Debt payments - 15 yrs	$	6,176,901
Energy equipment	83.9%	$	59,785,600	**Annual Costs and Debt - Total**	**$**	**9,202,567**
Balance of plant	7.7%	$	5,493,520			
Miscellaneous	6.8%	$	4,874,588	**Annual Savings or Income**		
Initial Costs - Total	100.0%	**$**	**71,237,908**	Energy savings/income	$	10,631,028
				Capacity savings/income	$	-
Incentives/Grants		$	-			
				GHG reduction income - 21 yrs	$	6,086
				Annual Savings - Total	**$**	**10,637,113**
Periodic Costs (Credits)						
		$	-			
		$	-			
		$	-			
End of project life - Credit		$	-			

Financial Feasibility

			Calculate energy production cost?	yes/no	Yes
Pre-tax IRR and ROI	%	31.1%	Energy production cost	$/kWh	0.0528
After-tax IRR and ROI	%	31.1%	Calculate GHG reduction cost?	yes/no	No
Simple Payback	yr	9.4			
Year-to-positive cash flow	yr	3.9	Project equity	$	7,123,791
Net Present Value - NPV	$	28,244,174	Project debt	$	64,114,117
Annual Life Cycle Savings	$	3,111,606	Debt payments	$/yr	6,176,901
Benefit-Cost (B-C) ratio	-	4.96	Debt service coverage	-	1.26

Yearly Cash Flows

Year #	Pre-tax $	After-tax $	Cumulative $
0	(7,123,791)	(7,123,791)	(7,123,791)
1	1,586,775	1,586,775	(5,537,015)
2	1,742,049	1,742,049	(3,794,966)
3	1,900,428	1,900,428	(1,894,538)
4	2,061,975	2,061,975	167,436
5	2,226,752	2,226,752	2,394,188
6	2,394,825	2,394,825	4,789,013
7	2,566,260	2,566,260	7,355,273
8	2,741,836	2,741,836	10,097,109
9	2,920,211	2,920,211	13,017,319
10	3,102,153	3,102,153	16,119,472
11	3,287,734	3,287,734	19,407,206
12	3,477,027	3,477,027	22,884,233
13	3,670,105	3,670,105	26,554,338
14	3,867,045	3,867,045	30,421,383
15	4,067,924	4,067,924	34,489,307
16	10,449,721	10,449,721	44,939,029
17	10,658,716	10,658,716	55,597,744
18	10,871,890	10,871,890	66,469,634
19	11,089,328	11,089,328	77,558,962
20	11,311,114	11,311,114	88,870,077
21	11,537,337	11,537,337	100,407,414
22	11,757,734	11,757,734	112,165,148
23	11,992,889	11,992,889	124,158,037
24	12,232,747	12,232,747	136,390,784
25	12,477,402	12,477,402	148,868,186

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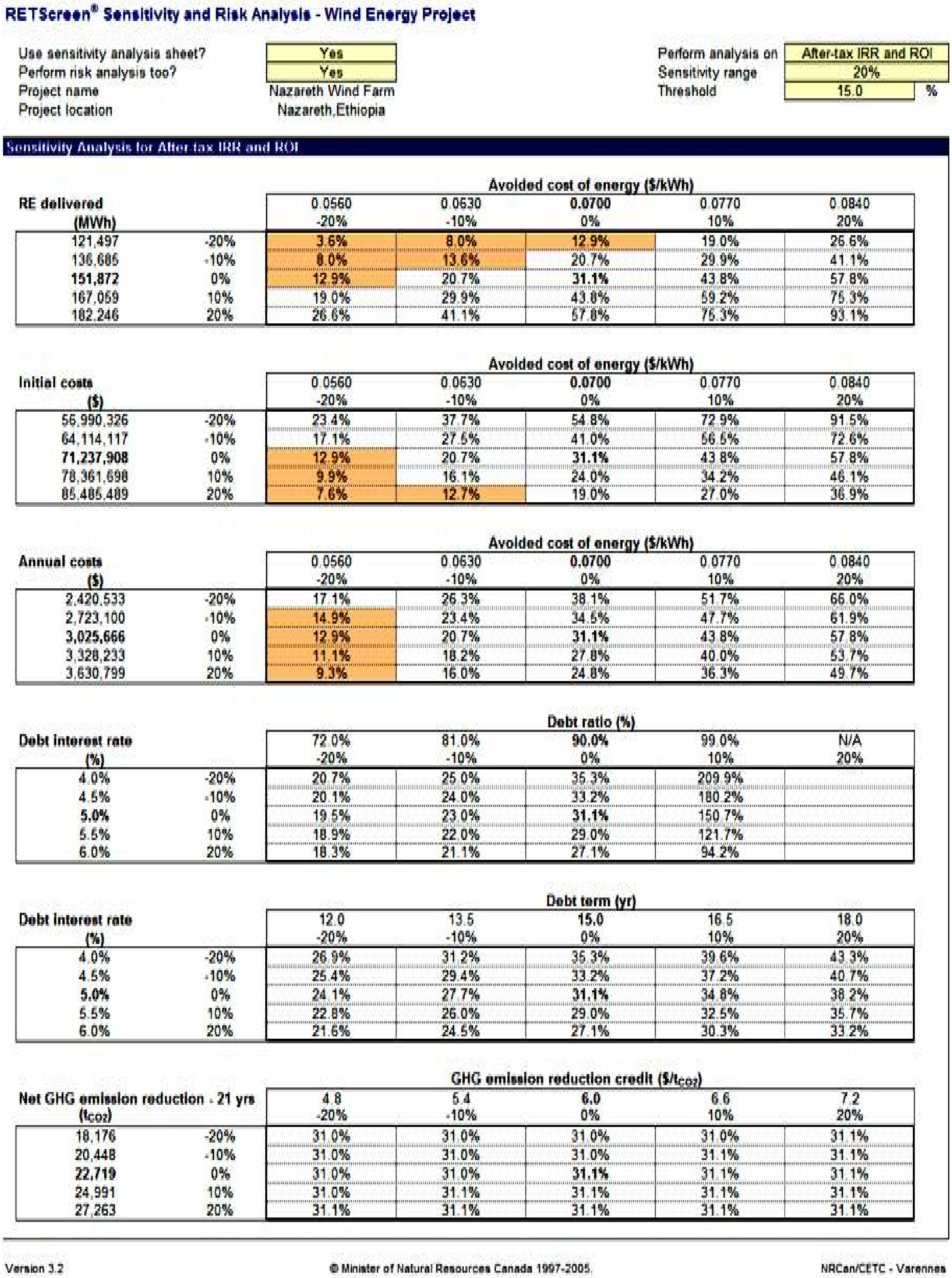

RETScreen® Sensitivity and Risk Analysis - Wind Energy Project

Use sensitivity analysis sheet?	Yes	Perform analysis on	After-tax IRR and ROI
Perform risk analysis too?	Yes	Sensitivity range	20%
Project name	Nazareth Wind Farm	Threshold	15.0 %
Project location	Nazareth,Ethiopia		

Sensitivity Analysis for After-tax IRR and ROI

Avoided cost of energy ($/kWh)

RE delivered		0.0560	0.0630	**0.0700**	0.0770	0.0840
(MWh)		-20%	-10%	0%	10%	20%
121,497	-20%	3.6%	8.0%	12.9%	19.0%	26.6%
136,685	-10%	8.0%	13.6%	20.7%	29.9%	41.1%
151,872	0%	12.9%	20.7%	**31.1%**	43.8%	57.8%
167,059	10%	19.0%	29.9%	43.8%	59.2%	75.3%
182,246	20%	26.6%	41.1%	57.8%	75.3%	93.1%

Avoided cost of energy ($/kWh)

Initial costs		0.0560	0.0630	**0.0700**	0.0770	0.0840
($)		-20%	-10%	0%	10%	20%
56,990,326	-20%	23.4%	37.7%	54.8%	72.9%	91.5%
64,114,117	-10%	17.1%	27.5%	41.0%	56.5%	72.6%
71,237,908	0%	12.9%	20.7%	**31.1%**	43.8%	57.8%
78,361,698	10%	9.9%	16.1%	24.0%	34.2%	46.1%
85,485,489	20%	7.6%	12.7%	19.0%	27.0%	36.9%

Avoided cost of energy ($/kWh)

Annual costs		0.0560	0.0630	**0.0700**	0.0770	0.0840
($)		-20%	-10%	0%	10%	20%
2,420,533	-20%	17.1%	26.3%	38.1%	51.7%	66.0%
2,723,100	-10%	14.9%	23.4%	34.5%	47.7%	61.9%
3,025,666	0%	12.9%	20.7%	**31.1%**	43.8%	57.8%
3,328,233	10%	11.1%	18.2%	27.8%	40.0%	53.7%
3,630,799	20%	9.3%	16.0%	24.8%	36.3%	49.7%

Debt ratio (%)

Debt interest rate		72.0%	81.0%	**90.0%**	99.0%	N/A
(%)		-20%	-10%	0%	10%	20%
4.0%	-20%	20.7%	25.0%	35.3%	209.9%	
4.5%	-10%	20.1%	24.0%	33.2%	180.2%	
5.0%	0%	19.5%	23.0%	**31.1%**	150.7%	
5.5%	10%	18.9%	22.0%	29.0%	121.7%	
6.0%	20%	18.3%	21.1%	27.1%	94.2%	

Debt term (yr)

Debt interest rate		12.0	13.5	**15.0**	16.5	18.0
(%)		-20%	-10%	0%	10%	20%
4.0%	-20%	26.9%	31.2%	35.3%	39.6%	43.3%
4.5%	-10%	25.4%	29.4%	33.2%	37.2%	40.7%
5.0%	0%	24.1%	27.7%	**31.1%**	34.8%	38.2%
5.5%	10%	22.8%	26.0%	29.0%	32.5%	35.7%
6.0%	20%	21.6%	24.5%	27.1%	30.3%	33.2%

GHG emission reduction credit ($/$t_{CO2}$)

Net GHG emission reduction - 21 yrs		4.8	5.4	**6.0**	6.6	7.2
(t_{CO2})		-20%	-10%	0%	10%	20%
18,176	-20%	31.0%	31.0%	31.0%	31.0%	31.1%
20,448	-10%	31.0%	31.0%	31.0%	31.1%	31.1%
22,719	0%	31.0%	31.0%	**31.1%**	31.1%	31.1%
24,991	10%	31.0%	31.1%	31.1%	31.1%	31.1%
27,263	20%	31.1%	31.1%	31.1%	31.1%	31.1%

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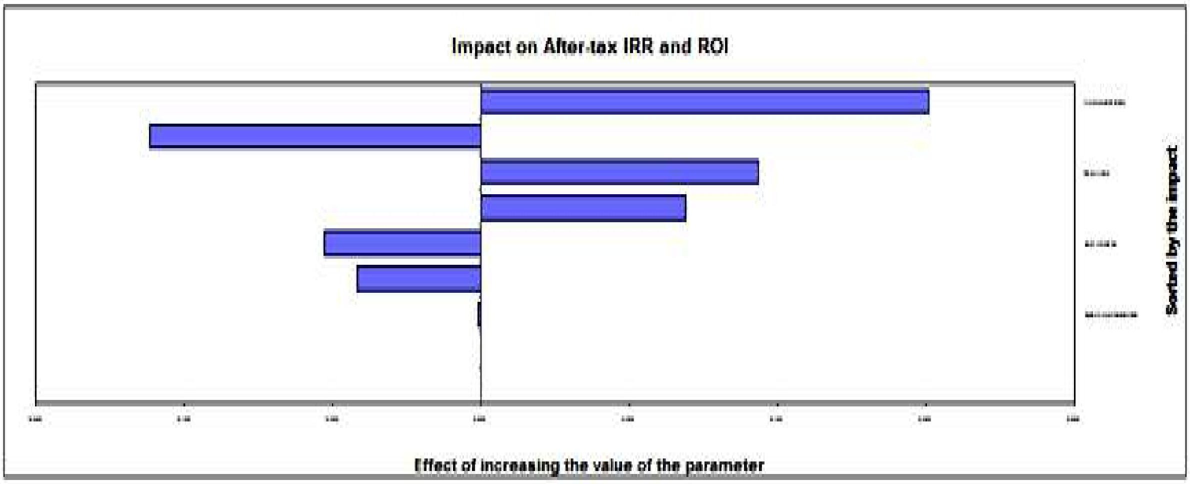
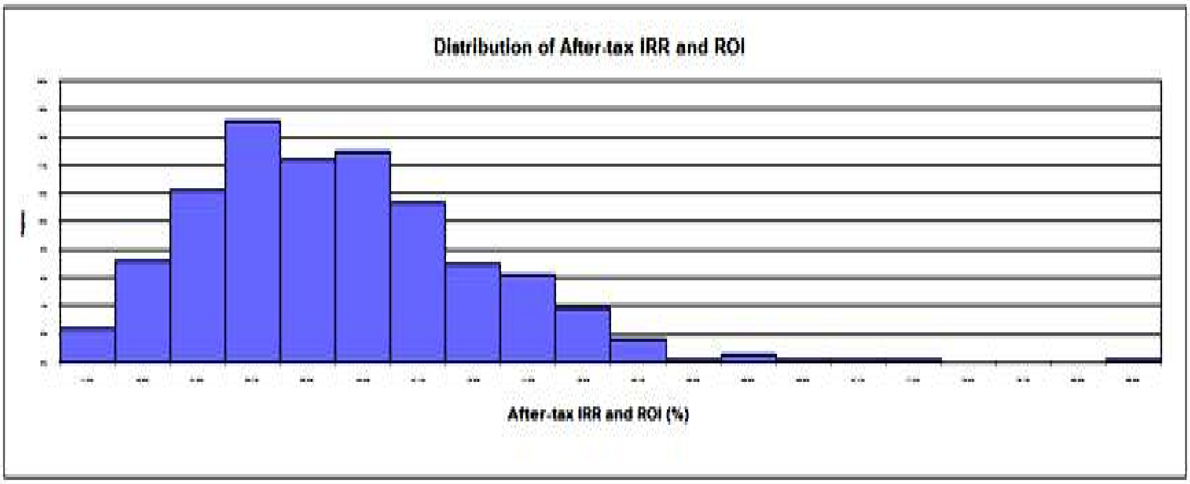
Risk Analysis for After-tax IRR and ROI

Parameter	Unit	Value	Range (+/-)	Minimum	Maximum
Avoided cost of energy	$/kWh	0.0700	15%	0.0595	0.0805
RE delivered	MWh	151,872	10%	136,685	167,059
Initial costs	$	71,237,908	15%	60,552,222	81,923,594
Annual costs	$	3,025,666	15%	2,571,816	3,479,516
Debt ratio	%	90.0%	5%	85.5%	94.5%
Debt interest rate	%	5.0%	30%	3.5%	6.5%
Debt term	yr	15	0%	15	15
GHG emission reduction credit	$/tCO2	6.0	20%	4.8	7.2



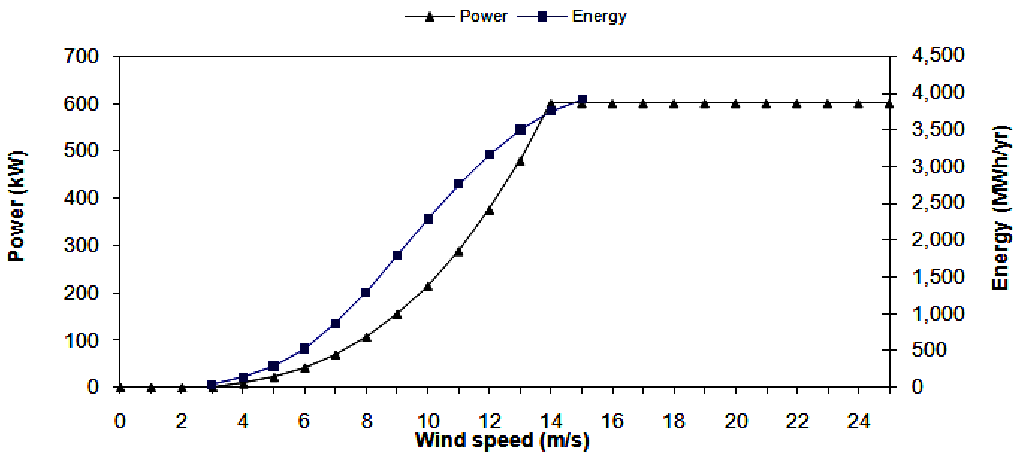
Median	%	30.4%
Level of risk	%	10%
Minimum within level of confidence	%	17.9%
Maximum within level of confidence	%	48.3%



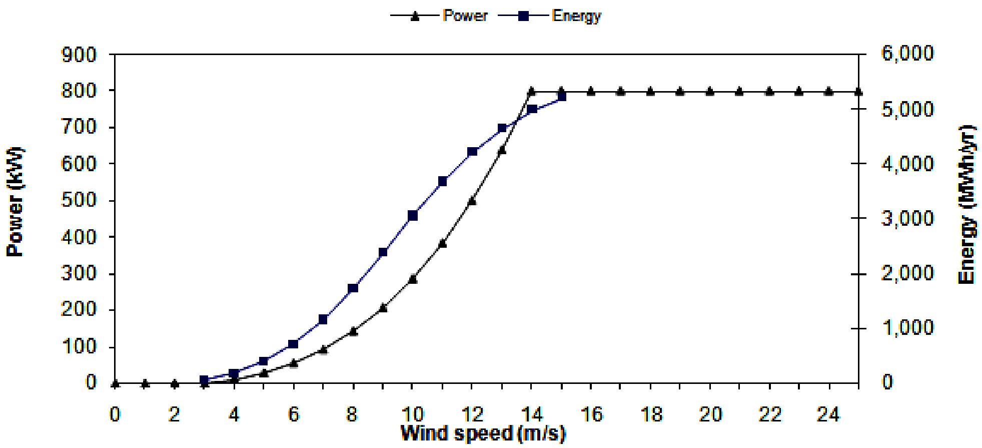
5.0%	Minimum	Median Level of confidence = 90%	Maximum	5.0%
	17.9%	30.4%	48.3%	

Annex A-2: The Power and Energy Curve of (a) 600, (b) 800 and (c) 1000 kW Turbine size, from RETScreen model.

(a)



(b)



(c)