IMPACT ANALYSIS FOR INTEGRATION OF WIND POWER GENERATION IN COLOMBIA

PROGRESS STUDY REPORT 02:

AEP AND FINANCIAL FEASIBILITY

400 MW WIND FARM PROJECT

OCTOBER 2014

ADDRESS COWI A/S
Parallelvej 2
2800 Kongens Lyngby
Denmark

TEL +45 56 40 00 00
FAX +45 56 40 99 99
WWW cowi.com

IMPACT ANALYSIS FOR INTEGRATION OF WIND POWER GENERATION IN COLOMBIA

PROGRESS STUDY REPORT 02:

AEP AND FINANCIAL FEASIBILITY

400 MW WIND FARM PROJECT

OCTOBER 2014

PROJECT NO.	A-038811
DOCUMENT NO.	PSR02
VERSION	2
DATE OF ISSUE	21 Oct. 14
PREPARED	KELA, ANJS, FLLS
CHECKED	ANJS, FLLS, LOBU
APPROVED	KELA

CONTENTS

List of Abbreviations

AEP	Annual Energy Production
CAPEX	Capital Expenditures
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CERE	Real equivalent Cost of the Capacity Charge
COP	Colombian Peso
E	East
ENE	East-NorthEast
ENFICC	Energía Firme para el Cargo por Confiabilidad – Firm energy
EPC	Engineering, Procurement and Construction
EUR	EURO
GWh	GigaWatt hour
IRR	Internal Rate of Return
kV	KiloVolt
LCoE	Levelized Cost of energy
LEC	Levelized Energy Cost
MCP	Measure Correlate Predict
m/s	meter per second
MW	MegaWatt
NPV	Net Present Value
O&M	Operation and Maintenance
OPEX	Operational Expenditures
PPA	Power Purchase Agreement
US$	United States Dollars
WTG	Wind Turbine Generator
y	Year

Exchange rate:	US$/EUR: 1.38
	COP/US$: 1,880

1 Introduction & executive summary

1.1 Introduction

In accordance with the terms of reference for the assignment AEP calculations for two turbine types and a cost structure and economic calculations should be carried out for the two designated regions La Guajira and Santander respectively.

However, as it has turned out to be impossible to obtain useful wind data measured on MET masts for the Santander region, calculations for this region have not been performed.

In this report, therefore, only an indicative wind study for a defined site in the La Guajira region is presented along with financial assumptions, cash flow calculations and conclusions on economic feasibility.

1.2 Executive summary

Based on the received information and data a wind study and financial feasibility analyses were carried out for a fictive 400 MW wind power project located in La Guajira region.

The average mean wind speed at the project site has been estimated to 8.2 m/s at 50 m above ground level, which is relatively high compared with other sites internationally. There is a general high wind period during Jan-Aug and low wind period during Sep-Dec.

Based on the wind data analyses, and on two different wind turbine scenarios:

› 200 wind turbines with individual capacity of 2 MW

› 134 wind turbines with individual capacity of 3 MW

The corresponding annual net energy production has been calculated:

› 1,661,000 MWh per year with 2 MW wind turbines

› 1,768,000 MWh per year with 3 MW wind turbines

The financial analyses performed on the two scenarios, and based on information gathered from Colombian developers show that the project in the base case is considered be financially viable. This applies to both scenarios and to all cases; pure investment (i.e. no financing included), base case market financing and alternative case market financing.

Sensitivity analyses show that the project is very sensitive to changes in the tariff and in the investment cost. A change in the ENFICC also affects the financial viability, but to a lesser extent than the other two parameters.

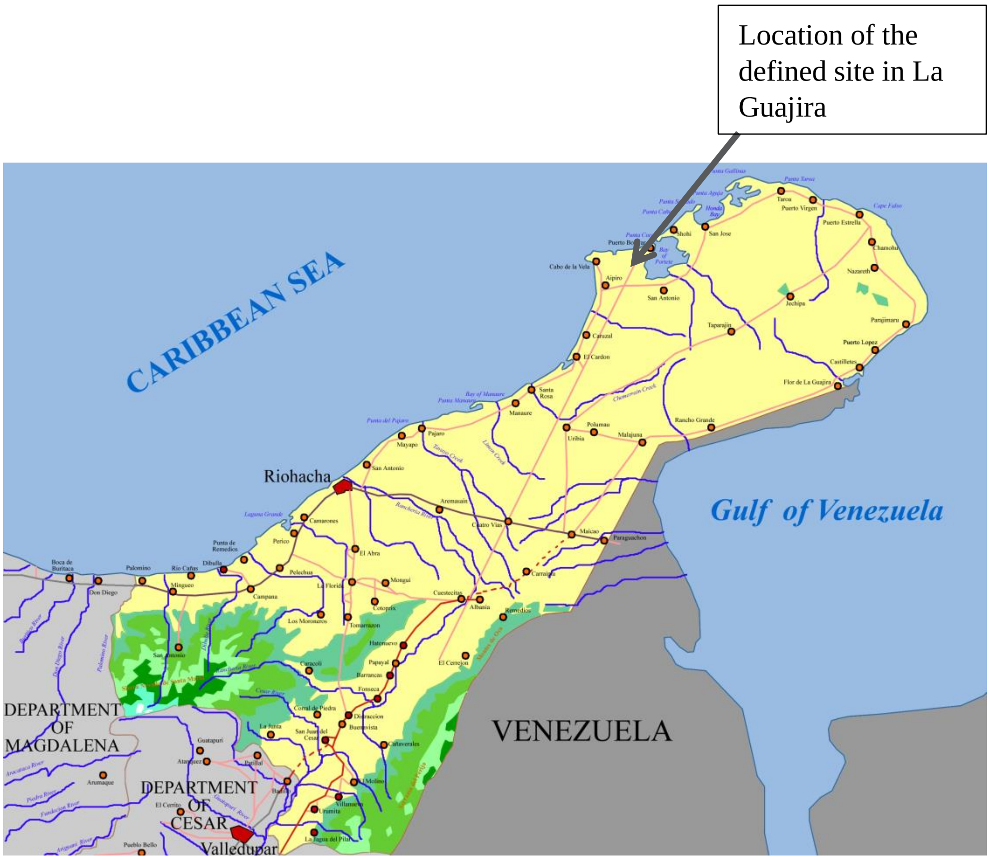
Levelized cost of energy for the project has also been estimated. In order to reach the expectation of 10% IRR, the required tariff for the different cases would be:

Case	USD/per MWh - 2MW	USD/per MWh – 3 MW
Pure investment	92.29	88.06
Base case market financing	77.75	74.33
Alternative market financing	76.53	73.18

This shows that the tariff 89.7 USD per MWh (from the current average of the spot market price in 2013) is sufficient, in order to reach an IRR of 10%.

2 400 MW Wind Farm, La Guajira – wind study

In this chapter wind data and average annual energy production (AEP) for a fictive 400 MW project in La Guajira region is presented. As this is merely an indicative calculation for a fictive project, specific site conditions such as extreme wind and turbulence have not been taken into account. The location of the project has been determined as a consequence of the wind data made available by UPME.



It should be noted that the presented wind study and AEP estimate for the fictive project must not be considered as a study of bankable quality, but as an indicative study only.

The reason is that the available information about the measurements provided by UPME is very limited and not applicable for estimation of the uncertainty of the measured wind. Furthermore, the measurements have not been inspected by COWI and therefore, a thorough assessment of the data quality is not possible. Finally, the uncertainty of many other parameters (e.g. final location of project, selected turbine, O&M etc.), which cannot be determined at this point, will have an influence on the joint uncertainty of the AEP estimate. Therefore, a joint uncertainty of the estimated AEP has not been presented.

2.1 Data provided from UPME

The following wind data has been provided by UPME. Please note that very limited information about the measuring conditions and the met masts is available.

2.1.1 MET Stations, 10 m masts

Hourly wind direction and wind speed data from a 10 m mast covering the eight and half year period from January 2001 to June 2009 has been provided. The average measured mean wind speed during this period is 6.1 m/s. The data is presented in monthly tables, which is not applicable in wind analysis tools. Therefore, the data has been reorganized into a time series, and wind directions have been changed to numerical values.

The mast location is: 12.13° N; 71.59° W (see Figure 1).

2.1.2 Met Station, 50 m mast

Hourly wind direction and wind speed data from a 50 m mast covering the six years and seven months period from January 2007 to July 2013 has been provided. The average measured mean wind speed during this period is 7.5 m/s. These data is also presented in monthly tables, and has therefore been reorganized into a time series.

The mast location is: 12.2313° N; 72.04° W (see Figure 1).

2.1.3 Jepirachi Wind Farm

Production and availability data from the existing Jepirachi wind farm covering the period 2004 – 2012 has been provided (see Figure 1).

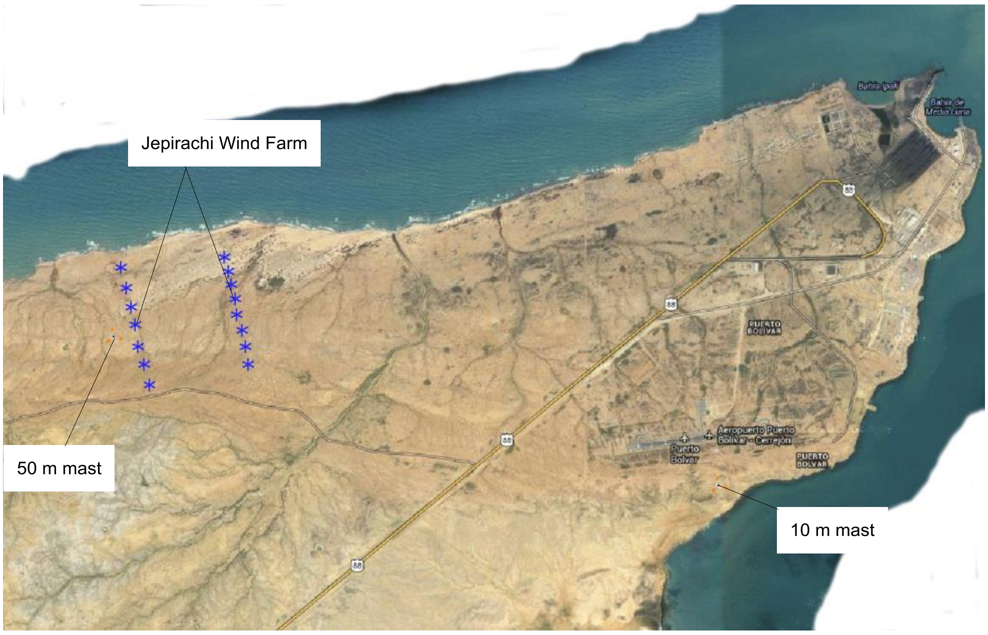


Figure 1 Location of 10m and 50m masts and Jepirachi Wind Farm

2.1.4 Combination of data

Figure 2 shows the correlation between the 10 m mast and 50 m mast weekly mean wind speeds. It shows that there is a very good correlation with a correlation coefficient $R^2 = 0.95$.

Therefore, the 10 m mast and 50 m mast can be combined by a MCP[1] substitution method into a full 12-year time series representing the wind speed as if it was measured at the 50 m mast (see section 2.2.2).

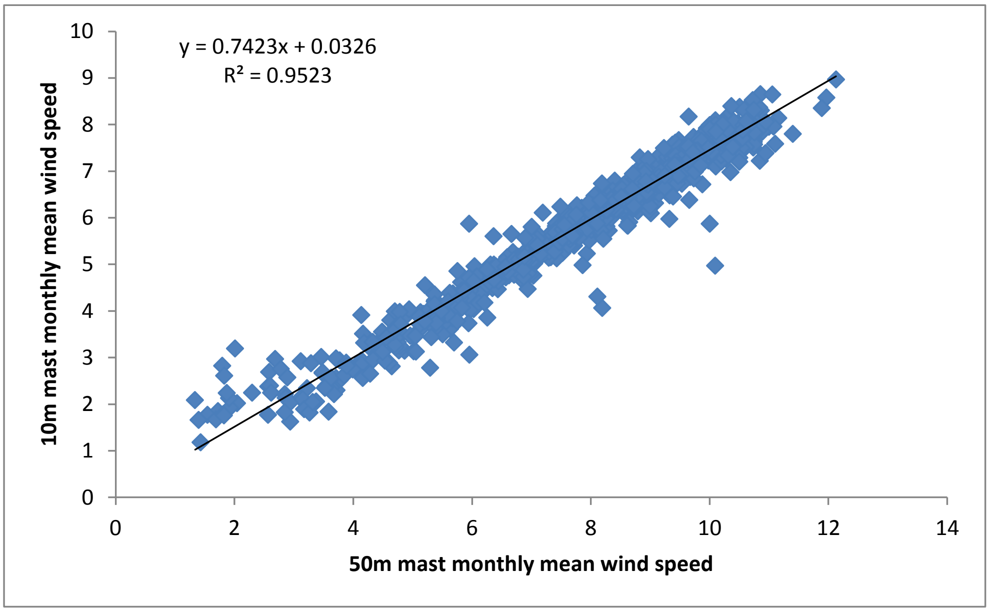


Figure 2 Correlation between 10 m mast and 50 m mast monthly mean wind speeds

[1] Measure Correlate Predict

2.1.5 Long-term reference and correction

No long-term reference data from a nearby meteorological station is available, and therefore, in order to assess the long-term wind climate, MERRA data[2] covering a 30-year period has been applied in the analysis. A correlation coefficient $R^2 = 0.85$ based on monthly mean wind speeds has been found between the MERRA data and the 50 m mast data as shown in Figure 3, which is acceptable for long-term correction.

Before performing the long-term correction of the onsite time series, it is necessary to check the long-term reference data for trend, which could be caused by the applied meteorological sources and not a real trend in the wind. The result shows that the MERRA data has a trend through the selected 30 years period as shown in Figure 4. It is assessed that this declining tendency in the wind is not due to a general decrease in the wind, as this is not expected. The reason is most likely that the meteorological sources have changed during time, which has been seen in other cases too. Therefore, a de-trending analysis of the MERRA data by a correction according to the linear trend seen in Figure 4 has been carried out before the data is used as reference for the long-term correction of the 12 years 50 m mast time series. The de-trended MERRA data is shown in Figure 5.

By comparing the 30 year annual mean wind speed with the annual mean wind speed during the 12 years based on the MERRA data, it shows that the annual mean wind speeds during the two periods are identical:

› Mean wind speed during the 12 years period: 9.0 m/s

› Mean wind speed during the 30 years period: 9.0 m/s

This corresponds to a long-term correction of the 12 years onsite data of 1.0.

If the MERRA data was not de-trended, the long-term correction of the 12 years should have been +3 per cent.

[2] NCAR and MERRA re-analysis data is based on several different meteorological sources (satellites, balloons, meteorological stations etc.) and covers the entire world with a grid resolution of 2.5 and 1 degrees, respectively.

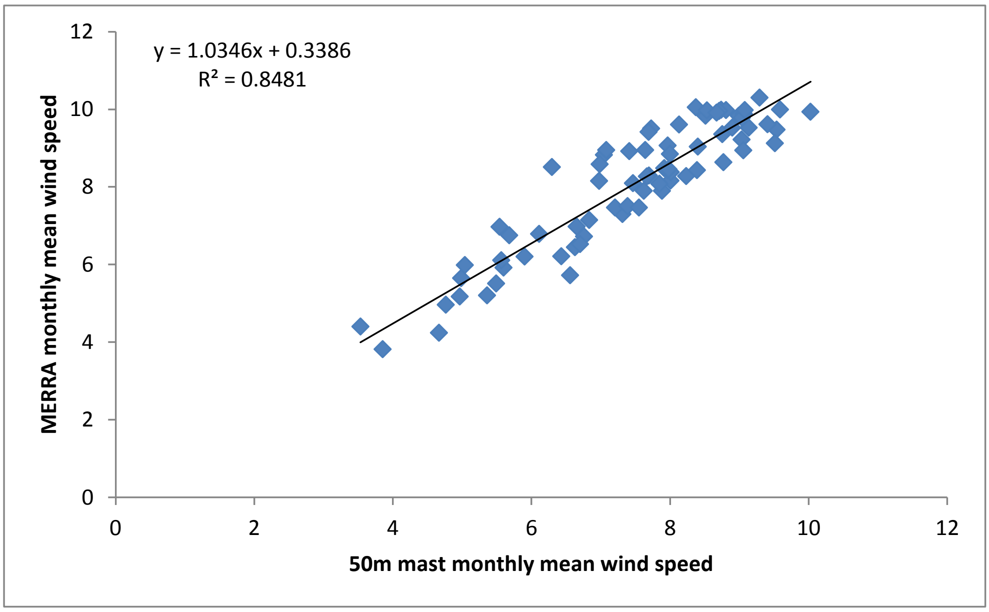


Figure 3 Correlation between MERRA and 50 m mast monthly mean wind speeds

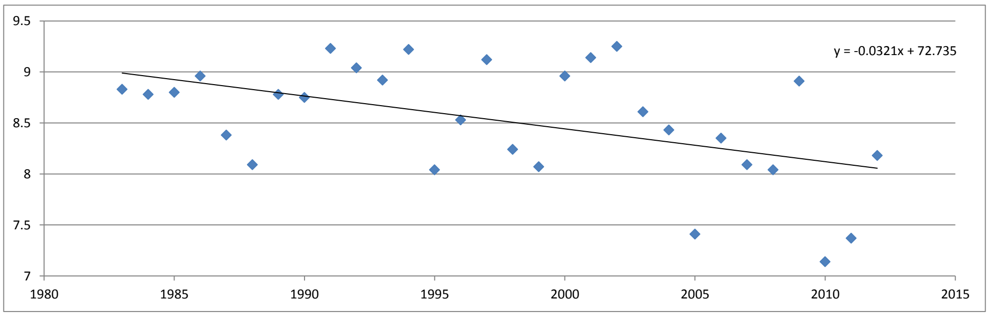


Figure 4 Raw MERRA annual mean wind speeds

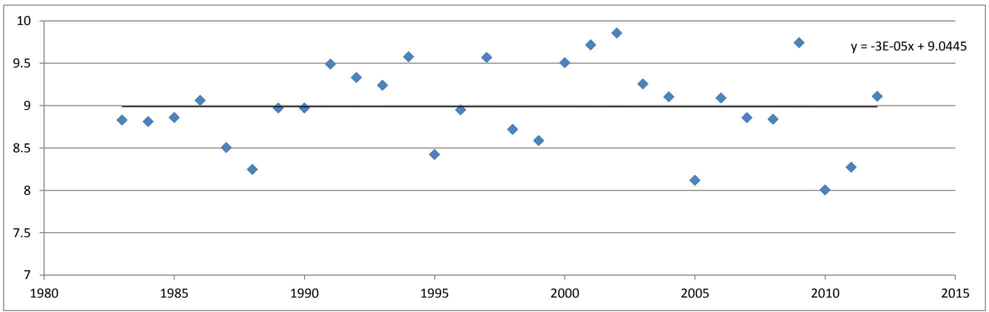


Figure 5 De-trended MERRA annual mean wind speeds

2.1.6 Correction for wake effect on 50 m mast data

The provided data from the 50 m mast covers the period from 2007, and during this period, the Jepirachi wind farm has been in operation.

The 50 m mast is located right west of the Jepirachi wind farm less than 300 m from the nearest wind turbine. The prevailing wind direction is E – ENE (east – east-northeast) with more than 98 per cent of the energy coming from these sectors.

Therefore, the wind speed measured at the 50 m mast is significantly influenced by the wake from the turbines and consequently lower than the free wind in the area.

The wake effect on the measured wind speed is determined by use of the wake model (N. O. Jensen) included in the WAsP[3] program, and it has been found that the wake loss on the wind seen by the 50 m mast corresponds to a reduction by 10 per cent compared with the free wind. This is verified by a comparison between the actual production from the Jepirachi wind farm and the predicted production using the 50 m wind speed data corrected by the 10 per cent (see section 2.3.1).

The same 10 per cent correction of the 50 m wind speed has been applied in the AEP calculations for the possible future 400 MW wind power project.

2.2 Wind analyses

2.2.1 Basic wind

The 12 years on-site data covering the period July 2001 to June 2013 - long-term corrected with the 30 years MERRA data - is used as basic wind for the following wind analyses and energy production estimate for the fictive wind project.

The monthly mean wind speed variation during the 12 years period is shown in Figure 6.

It is seen that there is a general high wind period during Jan-Aug and low wind period during Sep-Dec, with a maximum monthly wind of 11.0 m/s in May 2003 and a minimum monthly wind of 3.5 m/s in Oct 2007.

It is also seen that there is a significant variation in the annual mean wind speed, which correspond to a standard deviation of 12.5 per cent. This corresponds to a standard deviation in the AEP of more than 20 per cent. It should be noted that this yearly variation in the wind speed is significantly higher than usually seen for other wind project sites (see section 5.3 in the 38811-PSR03_Market_Reg report).

[3] Most commonly used program ("industry standard") worldwide for wind resource calculations

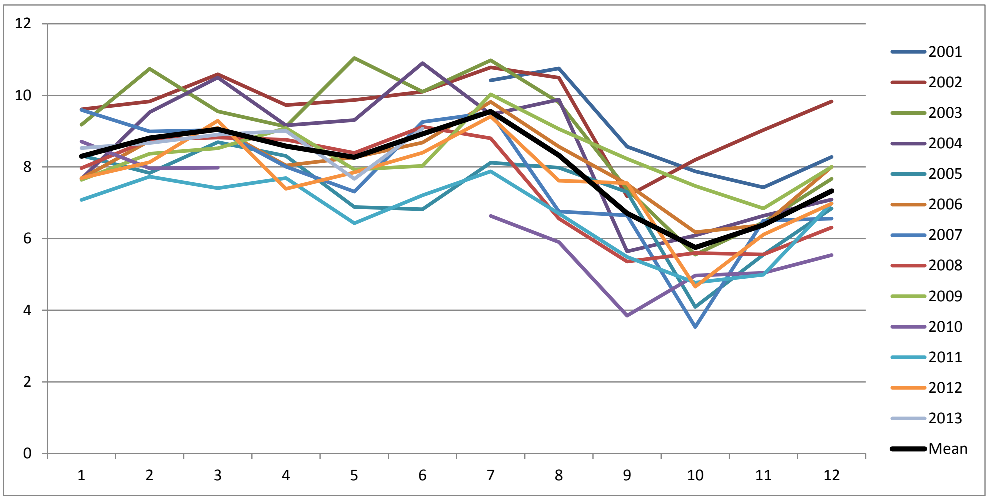


Figure 6 Monthly 50 m mean wind speed during the basic wind period

2.2.2 Wind distribution

The 12-year long-term corrected time series representing the wind measured at the 50 m mast are transformed into the Weibull distributions[4]. The Weibull distribution is shown in Figure 7.

The Weibull parameters are given by:

- Weibull A: 9.1 m/s
- Weibull k: 3.03
- Weibull mean wind speed: 8.2 m/s

Figure 8 shows the energy rose, and it is seen that the prevailing wind direction is E and ENE.

[4] Traditionally way of presenting the wind distribution used for wind energy

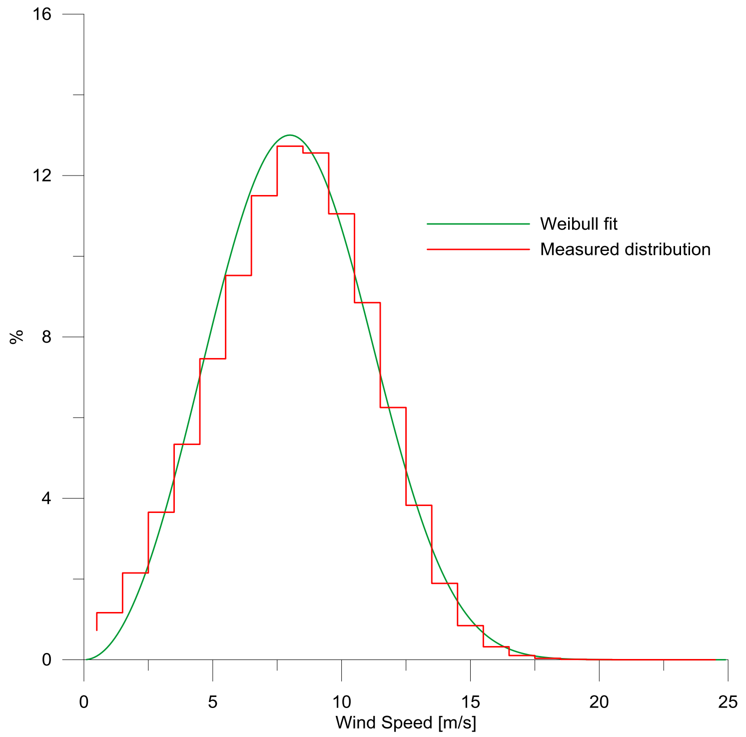


Figure 7 Measured wind distribution (red) and Weibull fit (green)

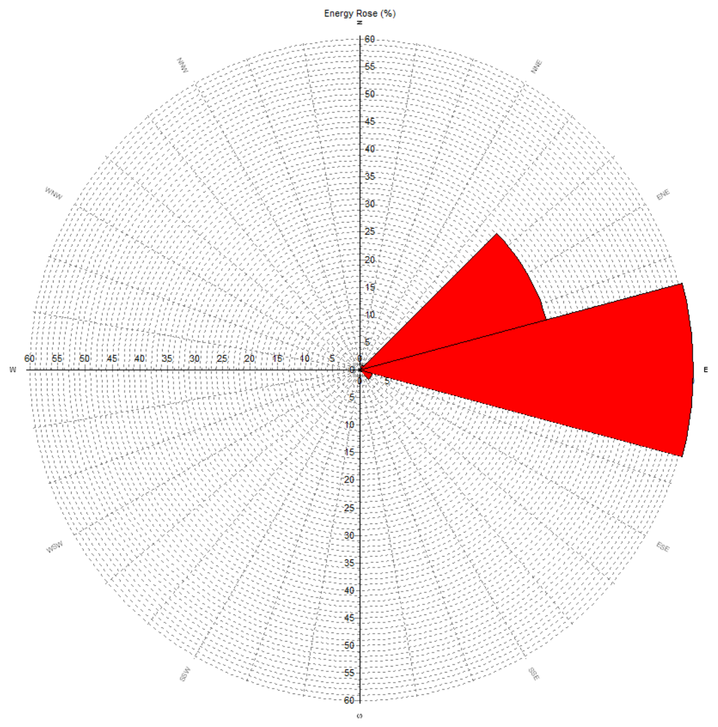


Figure 8 Energy Rose

2.3 Annual energy production estimate

The annual energy production (AEP) estimate for a possible future 400 MW wind power project located South-West of the existing Jepirachi wind farm has been calculated based on the available wind data.

The AEP calculations are carried out in WindPro, a program which calculations are based on WAsP flow model.

The following two wind turbines have been chosen:

- Gamesa G90 2 MW, hub height 78 m (200 x 2 MW)
- Vestas V112 3 MW, hub height 84 m (134 x 3 MW)

The turbine types have been selected based on the fact that in the terms of reference it was requested that both a 2 MW and a 3 MW turbine should be considered. Bearing this in mind, turbines from two of the most experienced wind turbine manufacturers who also have shown interest in projects in Central and South America have been selected.

With a mean wind speed of 8.2 m/s at 50 m above ground and estimated mean wind speed at 78 m hub height of 9.4 m/s and at 84 m hub height of 9.6 m/s, the area can be characterised as a medium-to-high wind area. However, as mentioned earlier specific site conditions (e.g. extreme wind) have not been taken into account when choosing the turbine types.

Further, micro-siting of the turbines have been done as regular rows without considering optimizing the lay-out with regard to terrain and site conditions. The orientation of the rows is north-south in order to minimize the internal wake loss and the distance between the rows is 7 rotor diameters (D). The in-row distance is 3D. This is a typical layout in a flat terrain with a dominating wind direction.

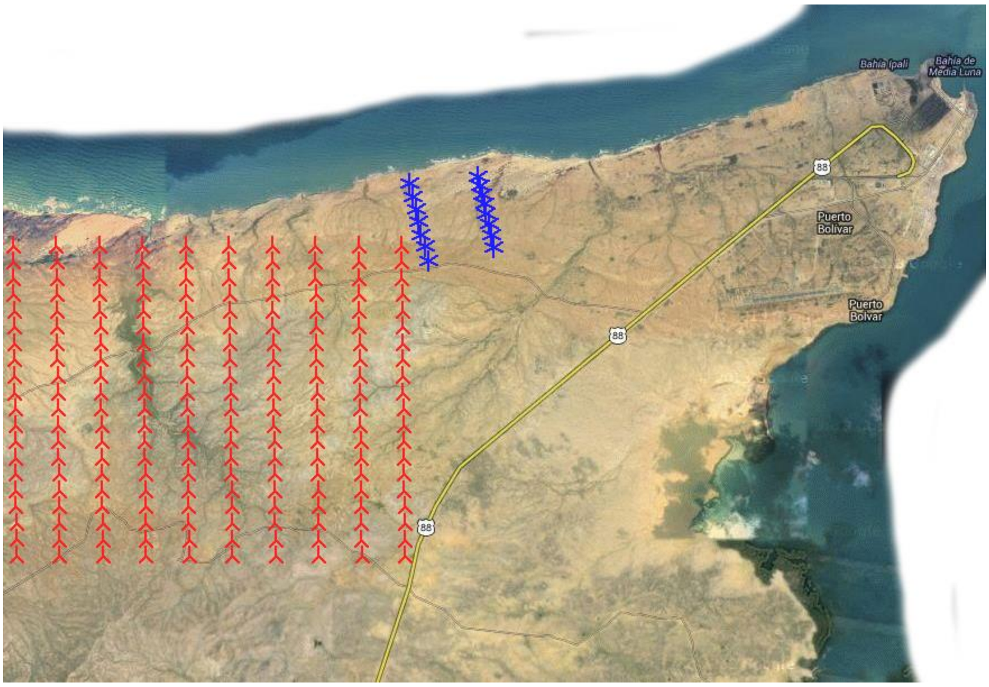


Figure 9 200x2 MW wind farm (⅄) and existing Jepirachi wind farm (⁎)

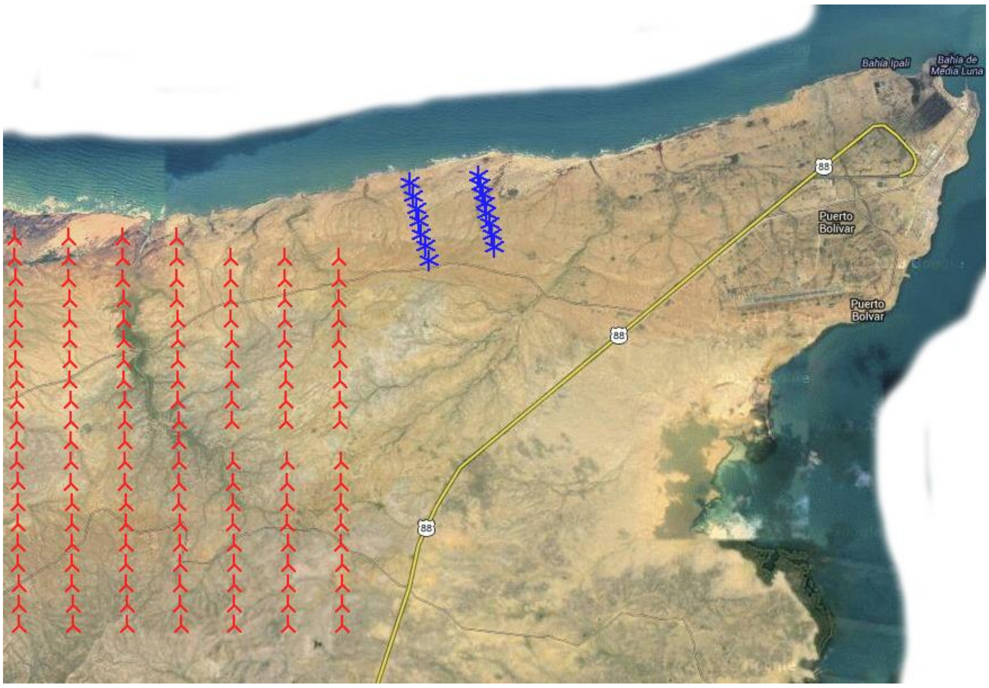


Figure 10 134x3 MW wind farm (⅄) and existing Jepirachi wind farm (⁎)

A terrain model based on satellite height contours (see Figure 11) and simple roughness map consisting of water and land has been created and a flow calculation using WAsP has been carried out in order to determine the energy production for the individual turbines. Furthermore, this calculation includes a calculation of the mutual wake loss.

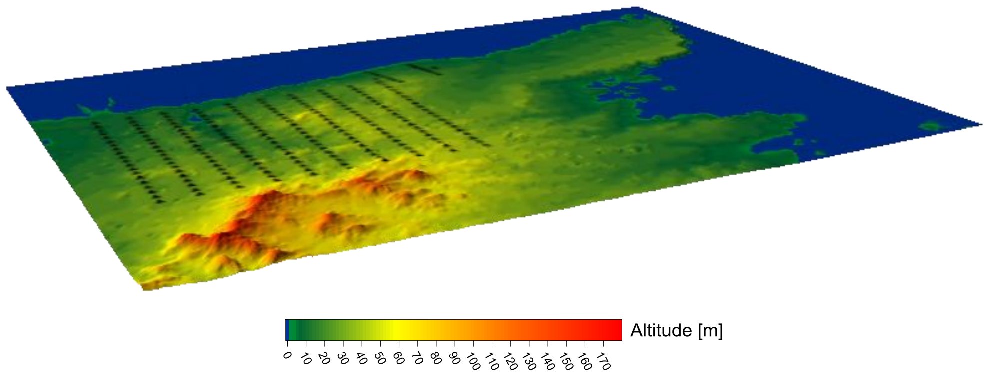


Figure 11 Terrain model seen from south-west including the 200x2MW layout and Jepirachi

In order to estimate the energy production delivered to the grid, some losses must be considered. At this stage the following losses – besides the calculated wake loss - are estimated based on experience with similar projects:

- Wind turbine availability loss: 4%
- Electrical loss: 4%
- Grid loss: 2%
- Power curve loss: 2%

The following AEP estimates have been obtained.

200 x Gamesa G90 2 MW, hub height 78 m		
AEP gross		2138 GWh/y
Wake loss[5]	12.2%	261 GWh/y
AEP park		1877 GWh/y
Losses:		
WTG availability	4%	
El Loss	4%	
Grid loss	2%	
Power curve loss	2%	
Total loss	11.5%	216 GWh/y
AEP-net		**1661 GWh/y**
Net Capacity factor		47 %
Full Load hours:		4153 hours

Table 1 AEP estimate for 200 Gamesa G90 2 MW, hub height 78 m

[5] Only wake loss from the new turbines is included as the location is not fixed. Possible wake loss from Jepirachi turbines will be insignificant

134 x Vestas V112 3 MW, hub height 84 m		
AEP gross		2249 GWh/y
Wake loss[5]	11.2%	252 GWh/y
AEP park		1997 GWh/y
Losses:		
WTG availability	4%	
El Loss	4%	
Grid loss	2%	
Power curve loss	2%	
Total loss	11.5%	229 GWh/y
AEP-net		**1768 GWh/y**
Net Capacity factor		50 %
Full Load hours:		4397 hours

Table 2 AEP estimate for 134 Vestas V112 3 MW, hub height 84 m

The AEP estimated are P50 probability figures. The uncertainty and consequently the P90 or P75 figures for the AEP are considered inappropriate for this preliminary study and are not estimated caused by the large numbers of unknown factors like the location of the wind farm, actual turbine, final micro sitting of the wind farm, accuracy of wind measurements etc.

2.3.1 Check of method against actual production from Jepirachi

The production data from the existing Jepirachi wind project has been corrected for availability in order to obtain production data as if the availability had been 100 per cent. This is done to make it comparable with the calculated productions. The availability for the Jepirachi wind project during the period 2005 to 2012 is depicted in Figure 12, and it is seen that it varies between 77 per cent in 2009 and 91 per cent in 2005. The average availability during the 8 years period is 84 per cent, which is considerably lower than seen for most wind power projects today and also considerably lower than estimated for the future wind project. The reason for the low availability is most likely due to grid loss, and to the fact that it is a demonstration project with a limited service and maintenance organisation and more difficult access to spare parts, crane etc.

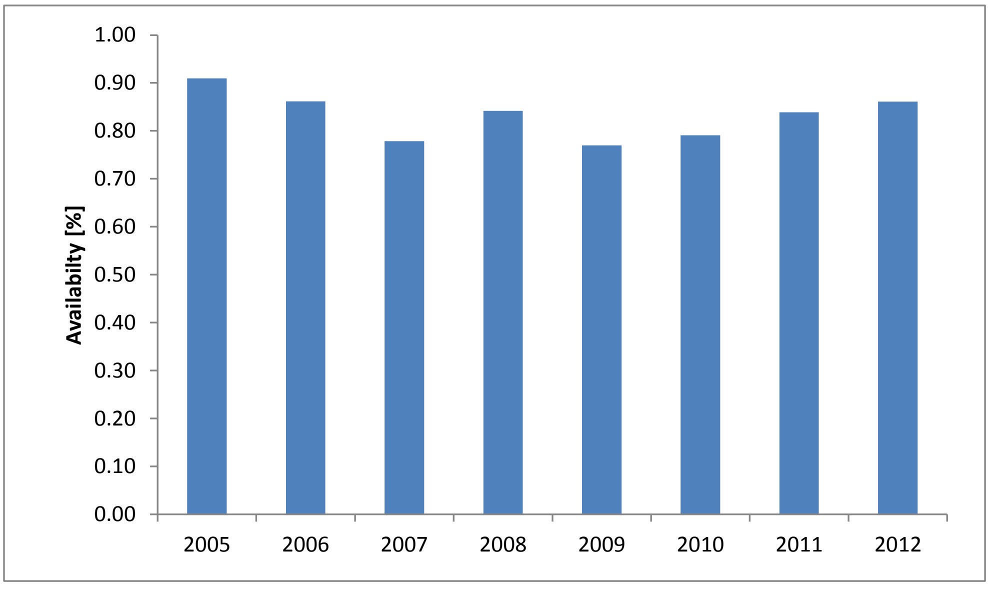


Figure 12 Jepirachi wind farm availability

Figure 13 shows the actual AEP and the calculated AEP for the Jepirachi wind farm using the same approach as used for the above AEP estimate for the possible future 400 MW wind power project. The AEP for the individual years is based on the energy content distribution based on the wind data.

It is seen that there is a very good agreement, which indicate that the approach used for estimating the energy production from a future wind project is applicable.

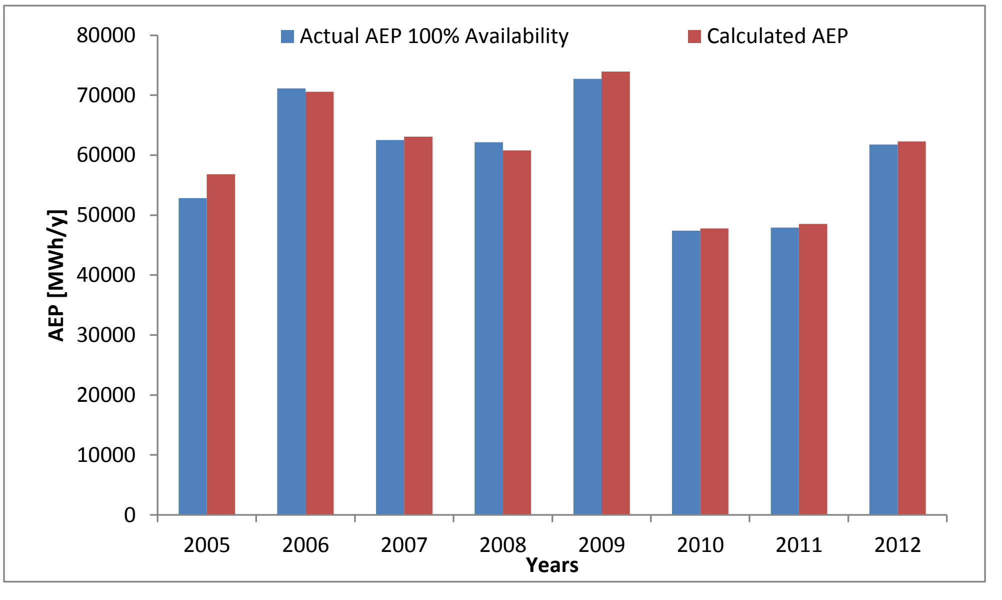


Figure 13 Actual and calculated AEP for Jepirachi

3 400 MW Wind Farm, La Guajira – financial feasibility

In this chapter the financial feasibility of a 400 MW wind farm in La Guajira is analysed.

As presented above in the wind study two scenarios with different turbine types have been studied resulting in two different annual energy productions. This would normally imply two different financial cash flow calculations, where also CAPEX and to some extent OPEX would be different. However, as it is very difficult to obtain precise information on the different parameters, mainly due to prices from manufactures being confidential information, it has been decided to use the same CAPEX and OPEX assumptions for both scenarios. The two different annual energy productions will instead be used as sensitivity scenarios on the production.

All income and cost is calculated at fixed prices with 2013 as the base year.

3.1 Energy production and CERs

The annual energy production is derived from the above wind study presented in chapter 3. There are two 400 MW scenarios presented:

- 200 wind turbines with individual capacity of 2 MW
- 134 wind turbines with individual capacity of 3 MW

The corresponding annual net energy production has been calculated to be:

- 1,661,000 MWh per year with 2 MW wind turbines
- 1,768,000 MWh per year with 3 MW wind turbines

A wind power project, if registered as a CDM[6] project, also produces certified emission reductions (CERs). CERs are emission reduction in tonnes CO2 per MWh electricity produced. The CERs are derived by multiplying the annual energy

[6] Clean Development Mechanism (CDM)

production with an emission factor (combined margin). In the case of Colombia the emission factor is relatively low as the main part of the existing electricity production stems from hydro power and thus also has close to zero emission related to the production. The emission factor for the Colombian electricity system is estimated at 0.292[7]. In the financial calculations only 95% of the generated CERs have been used for generating income. The reason for this is that 2% of the generated CERs must be paid in to the adaptation fund in the CDM system. The remaining 3% has been estimated as costs related to the annual reporting and registration of the CERs in the CDM system.

3.2 Investment and operation budget

3.2.1 Investment budget (CAPEX)

The CAPEX consists of the following items:

- EPC contract
- Transmission and grid connection cost
- Development cost (investigations, studies, permit/licenses etc.)
- CDM development and registration cost

EPC contract

It is assumed that the EPC contract for a 400 MW project will cover all project items up to and including the on-site substation (i.e. wind turbines, foundations, internal electrical network, 33/230 kV substation and all related civil works on site such as access roads, lay-down areas, administration/maintenance/control building etc.). Various international studies such as *"Renewable Energy Technologies: Cost Analysis Series - Wind Power"* by IRENA and various World Bank studies show that a figure of US$ 2 million per MW installed capacity is considered the price level at this point in time for this part of the world. However, indications from developers in Colombia show a somewhat lower estimate of between US$ 1.5 - 2 million per MW. Therefore, in order to take this into consideration but still maintain a conservative approach, an EPC cost of US$ 1.8 million per MW has been assumed for the calculations in the present report. This result in a total EPC cost for a 400 MW project of US$ 720 million.

Transmission and grid connection cost

Transmission and grid connection cost relates to the investment cost for a transmission line from the on-site project substation up to the grid connection point. Further, any possible reinforcement or up-scaling of the grid connection point to be paid by the project is included. Different estimates have been received from project developers with a transmission line ranging from 80 km to 130 km. However, this issue has also been assessed and the related costs estimated by the

---

[7] Informed by IDB

Consultant. Based on these analyses and calculations performed by the Consultant (ref. report 38811-PSR01_PSA Neplan Rev 0_11Nov13, tables 21-24) the cost of the transmission line and grid connection to be carried by the project as such has been estimated at USD 90 million.

Development cost

Development cost covers a range of different activities necessary for the development and preparation of a wind power project. Development cost varies a lot mainly depending on the level of experience of the project owner and the country's regulatory framework (i.e. environmental requirements, requirements to studies, permits, licenses etc.). Based on different information and the Consultant's experience normally 5-10% of the total investment cost is assessed to be realistic. In the present calculation as the project is very large, and as there will be economies of scale to some extent, an estimate of 5% of the EPC contract has been used. This equals total development cost of US$ 36 million for a 400MW project.

CDM development and registration cost

Generally, CDM development and registration cost range from US$ 33,000 up to US$ 185.000[8]. For wind power projects a fairly concise scheme has been established and wind projects are generally not considered complex projects. Further, CDM development and registration cost are not dependent on the size of the project. Hence, the cost will not vary if the size of the project is 100 MW or 400 MW. Therefore, and based on the Consultant's experience from other wind power projects, CDM development and registration costs have been set in the low end at US$ 50,000.

Total CAPEX

Based on the above the total CAPEX of a 400 MW project is estimated at US$ 846 million

CAPEX item	US$
EPC contract	720,000,000
Transmission & Grid connection	90,000,000
Development cost	36,000,000
CDM development cost	50,000
TOTAL	**846,050,000**

3.2.2 Implementation and lifetime periods

Planning and construction of a wind power project may take a number of years. Elaboration of studies, obtaining consents and permits from local authorities and landowners and carrying out a procurement process need a careful planning that could last 2-3 years before the construction works can commence. Once construction has commenced, it is assumed that 50 – 80 wind turbines can be installed per year, and therefore implementation of a 400 MW wind power project is estimated at approx. 2½ years. However, as the fictive project most likely will be implemented in smaller portions with shorter implementation time, and for the ease

[8] UNEP Risoe : *CDM Guideline 3rd edition, 2011*

of calculations, it is assumed that the investment is carried out in one year (the basis year 2013) and that the power generation from the wind turbines starts the year after, i.e. in 2014.

In line with normal industry practice the total lifetime of a wind power project is set at 20 years - equal to the design lifetime of the WTGs. Recently in relation to financial analyses the expected lifetime of WTGs has by some analysts been extended to 25 years, but as the certified estimated design life time is still set at 20 years this project period has been maintained in the present analysis. Thus, the total period considered in the analyses is from 2013 (basis year) to 2033 (end of lifetime).

3.2.3 Tariff, reliability charge and CERs

For a wind power project in Colombia there are different parameters related to income generation.

First of all the electricity will be sold on the market. This can be done at spot market prices, but preferably, the project will attempt to obtain a long term power purchase agreement (PPA)[9] with a utility or a similar off-taker. A long term PPA will offer a fixed tariff per kWh (MWh), and will thus ensure a steady and predictable income. The average whole spot price in 2013 has been informed by IDB to be US$ 89,7 per MWh. This figure has been used in the base scenario for the financial analysis.

In addition to the electricity tariff, wind power projects may receive a firm energy payment called a reliability charge. The maximum amount of firm energy that a generator may offer in a firm energy auction is known as its ENFICC which refers to the amount of energy a generator of a given type can reliably and continually produce during periods when hydro generation capacity is at a minimum. At the moment, under current regulation, the ENFICC for wind power projects is 6%. For the given project the basis for calculating the reliability charge is then 6% * 8760 hours * 400 MW = 210,240 MWh. The level of the reliability charge per MWh is informed to be US$ 15. This estimate is based on information from Colombian developers, the World Bank Study "Wind Energy in Colombia" and the University of Oxford study "Private investment in wind power in Colombia".

Currently, the market price for one CER[10] is around US$ 0.5, but different forecasts by international traders predict a price increase over the coming years to a level of around US$ 3 per CER. However, as the CER market is very hard to predict, and in order to keep a conservative approach, a CER price of US$ 1 per CER has been used in the financial calculations.

---

[9] It should be noted that long term PPAs in Colombia at present is around 2 years. Significantly longer PPAs (15-20 years) would be required if to provide comfort to the financing of wind farms.

[10] One CER equals reduction of one tonnes of CO2 equivalent

3.2.4 Operating costs (OPEX)

Below the operating costs (OPEX) are established by assessing the different components comprised in this item.

Operation and maintenance (O&M) agreement

It is assumed that a long-term agreement with the wind turbine supplier for operation and maintenance is entered into by the project. Previously, only short-term agreements of 2 - 5 years were offered by the wind turbine suppliers, but recently long-term agreements of 10-20 years have been presented. Although the majority of project owners still opt to take care of O&M themselves after a certain period, it has been decided to choose the long-term solution in this case, as it has been difficult to obtain country specific information in order to establish future O&M cost for a wind power project in Colombia.

A full operation and maintenance agreement is currently being offered at prices ranging between US$ 26,000 – US$ 55,000 per MW installed per year[11] As Colombia is a new market where wind turbine suppliers do not have service organizations already established, it is assumed that the cost will tend to be in the high end. On the other hand, with a potential of at least 400 MW service organizations will most likely be established in the country, and therefore an annual average cost of US$ 40,000 per MW is used in the calculations. This results in total annual O&M agreement cost of US$ 16 million.

Administrative cost

Even with a full O&M agreement, the project owner will still have certain administrative cost related to the staff handling project contracts, relations to the Grid Company and relevant authorities, book keeping and invoicing etc. For a project of this size it is estimated that at minimum the following organization will be needed:

- Manager/Director responsible for external relations and contract management,
- Financial person responsible for financial management and bookkeeping
- Legal adviser responsible for legal issues
- IT person responsible for software solutions and data handling and reporting to internal and external stakeholders.
- Secretary able to handle all common secretary work and assisting with bookkeeping, invoicing, reporting etc.

In addition to the above, also some site personnel will be needed. This is estimated to be minimum four persons.

The monthly salaries informed by IDB and assumed for relevant Employees are

---

[11] North American Wind Power: *"The real truth about wind farm O&M cost"*, March 2013 and figures from Colombian developers

Technicians	US$650 per month
Engineers	US$2000 per month
Administrative staff	USD$328 per month.

Based on the median salary an average annual salary of US$ 11,912 per staff has been estimated. With a relatively optimistic approach with regard to the number of staff totalling only 9 persons employed the annual salary cost will amount to US$ 107,208.

Other costs

Other costs cover items such as land lease, insurance, fees and charges such as CERE and transmission/grid charges.

The average yearly insurance cost is hard to estimate as it depends on many different issues and parameters. For the sake of the present financial calculations, an estimate of 0.25% of the investment cost related to the EPC and the transmission line and grid connection is used. The estimate is based information received from developers in Colombia and on the consultant's experience, and equals US$ 2.0 million per year.

The CERE fee is used to pay for the Reliability Charge. Each electricity generator contributes to a fund in proportion to the energy produced. At the same time, each power plant receives payments (reliability charge) from this fund, based on its contribution to firm energy in the energy mix. The CERE fee used for the analyse is US$ 16.9 per MWh (2013 average).

Colombian developers have informed that transmission line and substation O&M will be around US$ 9,500 per MW installed per year.

Finally, regulatory fees and yearly environmental costs according to information received from Colombian developers, amount to approx. US$11,000 per MW per year. This item also includes compensation for land use.

Income tax

Law 788 of 2002 establishes a 15-year tax-exemption period for power generated from wind or biomass energy. To benefit from this tax-exemption scheme, generators must obtain CERs, and 50 % of the income generated from this must be invested locally in social benefit programs. From year 16 and onwards the project will have to pay an income tax of 33%.

Depreciation

A 20-year linear depreciation has been assumed in the financial analysis and is considered after the 15-year tax-exemption period where the income taxes are considered.

3.3 Financial terms and assumptions

3.3.1 Discount rate

Based on information from the Central Bank of Colombia[12] a discount rate of 3.25% has been applied in the calculations.

3.3.2 Debt/equity ratio

A debt/equity ratio within a range between 60/40 up to 80/20 is normally seen for wind power projects with the 80/20 split becoming the norm. With Colombia, being a new market a conservative approach is therefore to consider a 70/30 debt/equity ratio. Hence, in the financing scenarios 70% of the total investment has been considered a loan provided on the given financing terms (ref. below).

3.3.3 Market financing terms

It has been difficult to obtain firm information on the financing terms that a wind project in Colombia could expect. Based on the information obtained from developers the following base case terms have been used in the calculations:

- Loan tenor (maturity): 15 years
- Repayment period: 15 years
- Instalments: every 6 months - first instalment 6 months after commencement of the repayment period
- Interest rate (base rate + spread): 7%

However, other indications on possible market terms have been received from financial institutions. These have been summarized into the following alternative financial case:

- Loan tenor (maturity): 10 years
- Repayment period: 10 years
- Instalments: every 6 months - first instalment 6 months after commencement of the repayment period
- Interest rate (base rate + spread): LIBOR(6 month – currently approx. 0.35%) + 5% spread

[12] http://www.banrep.gov.co/en

3.3.4 IRR requirement

According to the World Bank Study an IRR requirement of 14% is what a project developer would expect on a wind power project investment in Colombia. However, according to information received from different developers in Colombia an IRR of between 8 - 12% would be considered sufficient.

3.4 Financial analyses

In the financial analyses, the internal rate of return has been calculated for the pure investment without financing, and for the investment with financing on market terms.

3.4.1 Internal Rate of Return – pure investment without financing

Given the above listed assumptions and estimates the following results for the internal rate of return has been found for the pure investment without financing:

WTG type	Item	Result
2 MW	IRR	9,1 %
	NPV net income	463.371.420
3 MW	IRR	10,3%
	NPV net income	562.257.588

From this it can be seen that based on the current situation and on the assumptions made, a 400 MW wind power project in La Guajira can be considered financially viable. Compared with the IRR expectations from developers the result is aligned with their target, and compared with the base rate from the Central Bank of Colombia of 3.25 %, the IRR is well above this rate.

3.4.2 IRR – market based financing

Given the above listed assumptions and estimates the following results for the internal rate of return has been found for the investment with market financing:

Base case with market financing

WTG type	Item	Result
2 MW	IRR	17,1%
	NPV net income	562.082.629
3 MW	IRR	19,5%
	NPV net income	661.695.106

Base case with alternative market financing

WTG type	Item	Result
2 MW	IRR	16,6%
	NPV net income	646.733.049
3 MW	IRR	18,8%
	NPV net income	746.723.730

With both types of market based financing the IRR in the base case improves significantly.

3.4.3 Sensitivity analyses

To investigate the sensitivity of the investment different sensitivity scenarios have been carried out on selected parameters as being tabled below.

	Base Case	Scenario A	Scenario B	Scenario C
ENFICC	6%	10%	20%	30%
Tarif	89,7 $US/MWh	-10%	+10%	
Investment		-10%	-20%	
Power Connection	Included	Not included	Not included	
Depreciation	None	Considered in relation to income tax.		

The sensitivity analyses have been carried out on an "all other things being equal" basis. The results are shown in the two tables below one for each production scenario.

2MW	NPV	IRR	LCoE
Base case without fin.	463.371.420	9,14%	92,26
Base case with fin.	562.082.629	17,06%	77,75
Base case with fin. alternative	646.733.049	16,64%	76,53
ENFICC 10% without fin.	491.598.487	9,47%	92,26
ENFICC 10% with fin.	590.309.696	17,77%	77,75
ENFICC 10% with fin. alternative	674.960.116	17,25%	76,53
ENFICC 20% without fin.	562.166.154	10,28%	92,26
ENFICC 20% with fin.	660.877.363	19,56%	77,75
ENFICC 20% with fin. alternative	745.527.784	18,82%	76,53
ENFICC 30% without fin.	632.733.821	11,07%	92,26
ENFICC 30% with fin.	731.445.030	21,37%	77,75
ENFICC 30% with fin. alternative	816.095.451	20,40%	76,53
Tariff -10% without fin.	266.968.199	6,79%	92,26
Tariff -10% with fin.	365.679.408	12,17%	77,75
Tariff -10% with fin. alternative	450.329.829	12,44%	76,53
Tariff +10% without fin.	659.774.640	11,37%	92,26
Tariff +10% with fin.	758.485.849	22,06%	77,75
Tariff +10% with fin. alternative	843.136.270	21,02%	76,53
Investment -10% without fin.	538.964.547	10,61%	86,88
Investment -10% with fin.	646.648.852	20,77%	72,90
Investment -10% with fin. alternative	723.735.214	19,88%	71,79
Investment -20% without fin.	614.557.675	12,33%	81,50
Investment -20% with fin.	731.215.075	25,34%	68,04
Investment -20% with fin. alternative	800.737.379	23,95%	67,04
Power Interconnection cost not included without fin.	553.504.476	10,92%	85,85
Power Interconnection cost not included with fin.	662.705.184	21,56%	71,96
Power Interconnection cost not included with fin. alternative	738.350.773	20,58%	70,88
Depreciation not considered without fin.	463.371.420	9,14%	92,26
Depreciation not considered with fin.	525.651.555	16,81%	77,75
Depreciation not considered with fin. alternative	610.301.976	16,41%	76,53

3MW	NPV	IRR	LCoE
Base case without fin.	562.257.588	10,25%	88,03
Base case with fin.	661.695.106	19,50%	74,33
Base case with fin. alternative	746.723.730	18,77%	73,18
ENFICC 10% without fin.	591.405.782	10,58%	88,03
ENFICC 10% with fin.	690.843.300	20,25%	74,33
ENFICC 10% with fin. alternative	775.871.923	19,42%	73,18
ENFICC 20% without fin.	664.276.266	11,38%	88,03
ENFICC 20% with fin.	763.713.784	22,11%	74,33
ENFICC 20% with fin. alternative	848.742.407	21,06%	73,18
ENFICC 30% without fin.	737.146.750	12,18%	88,03
ENFICC 30% with fin.	836.584.267	23,99%	74,33
ENFICC 30% with fin. alternative	921.612.891	22,73%	73,18
Tariff -10% without fin.	353.202.264	7,82%	88,03
Tariff -10% with fin.	452.639.782	14,27%	74,33
Tariff -10% with fin. alternative	537.668.405	14,23%	73,18
Tariff +10% without fin.	771.312.913	12,54%	88,03
Tariff +10% with fin.	870.750.430	24,88%	74,33
Tariff +10% with fin. alternative	955.779.054	23,52%	73,18
Investment -10% without fin.	638.228.681	11,78%	82,95
Investment -10% with fin.	746.684.160	23,50%	69,74
Investment -10% with fin. alternative	824.110.905	22,30%	68,69
Investment -20% without fin.	714.199.774	13,59%	77,87
Investment -20% with fin.	831.673.215	28,43%	65,16
Investment -20% with fin. alternative	901.498.081	26,74%	64,21
Power Interconnection cost not included without fin.	652.390.644	12,10%	82,01
Power Interconnection cost not included with fin.	762.317.662	24,33%	68,89
Power Interconnection cost not included with fin. alternative	838.341.454	23,04%	67,86
Depreciation not considered without fin.	562.257.588	10,25%	88,03
Depreciation not considered with fin.	625.102.117	19,31%	74,33
Depreciation not considered with fin. alternative	710.130.740	18,58%	73,18

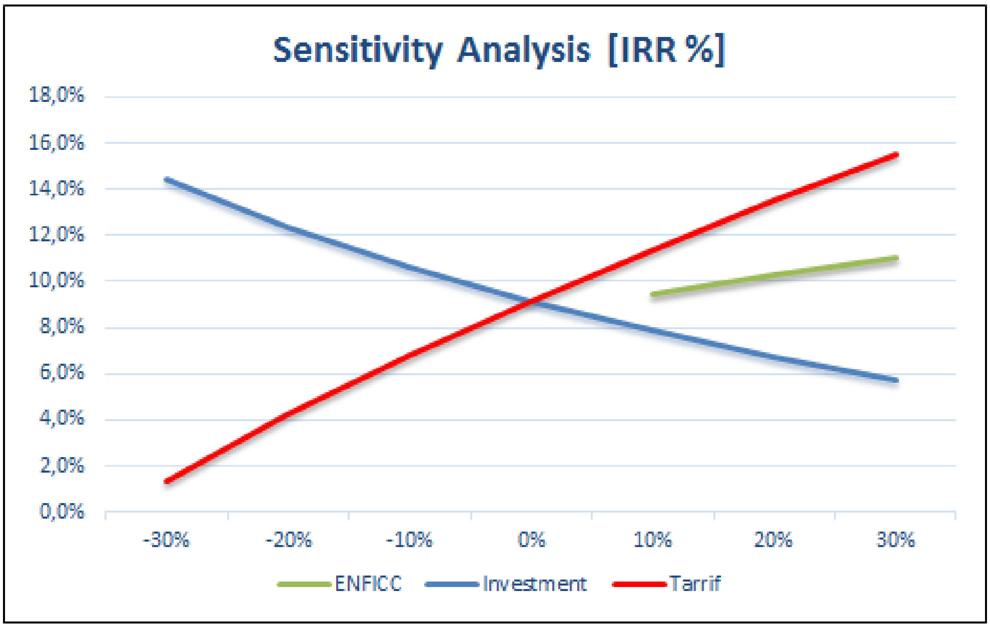
From the above tables it can be seen that the

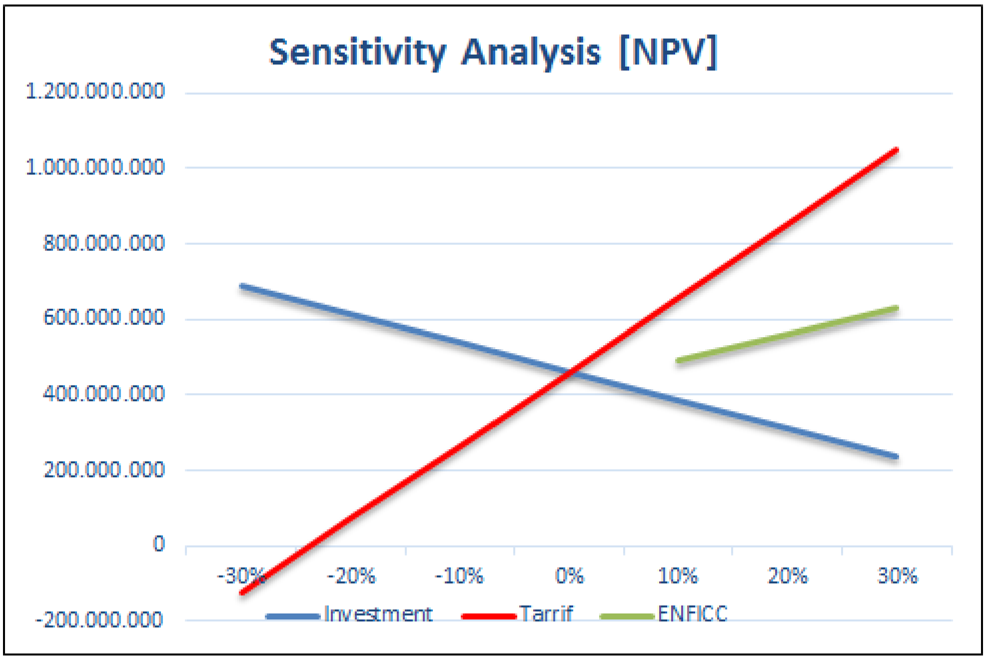
- Tariff & investment cost
  IRR is very sensitive to changes in the tariff and the investment cost.

- ENFICC
  IRR is also sensitive to changes in the ENFICC but to a lesser extent than for the two other parameters.

- Depreciation
  IRR & NPV are not significantly affected by the depreciation

A more illustrative sensitivity analyse for the 2MW WTG without financing is shown in the figures below when a change in the ENFICC, Investment and Tariff is introduced. (It is noticed that the ENFICC is 6% in the base case scenario and negative ENFICCs not apply).





3.5 Levelized Cost of Energy (LCoE)

Levelized cost of energy (LCoE) or levelized energy cost (LEC) is the price at which electricity must be generated from a specific source to break even over the lifetime of the project.

It can be defined in a single formula as:

$$\mathrm{LEC} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where

- LEC= Average lifetime levelized electricity generation cost
- I_t= Investment expenditures in the year *t*
- M_t= Operations and maintenance expenditures in the year *t*
- F_t= Fuel expenditures in the year *t*
- E_t= Electricity generation in the year *t*
- r= Discount rate
- n= Life of the system

3.5.1 LCoE – without financing

Calculated on the pure cash flow the following results are found:

Discount rate	LCoE USD/per MWh - 2MW	LCoE USD/per MWh – 3 MW
3.25 %	68.23	65.36
5.00 %	73.96	70.76
10.00 %	92.29	88.06

3.5.2 LCoE – market financing

Calculated on the cash flow with market financing the following results are found:

Base case market financing

Discount rate	LCoE USD/per MWh - 2MW	LCoE USD/per MWh – 3 MW
3.25 %	65.06	62.35
5.00 %	68,33	65.43
10.00 %	77.75	74.33

Alternative case market financing

Discount rate	LCoE USD/per MWh - 2MW	LCoE USD/per MWh – 3 MW
3.25 %	61.46	58.95
5.00 %	65,34	62.61
10.00 %	76,53	73.18

4 List of references

Besides the information received directly from the Client, IDB and from wind project developers in Colombia, the following references have been used:

1 International Renewable Energy Agency IRENA: *"Renewable Energy Technologies: Cost Analysis Series – Vol. 1, Issue 5/5 - Wind Power"*, June 2012

2 Oxford Institute for Energy Studies: *"Private Investment in Wind Power in Colombia"*, July 2012

3 UNEP Risoe: *"CDM Guideline 3rd edition"*, 2011

4 World Bank: *"Wind Energy in Colombia"*, July 2010