An Economic and Stakeholder Analysis for the Design of IPP Contracts for Wind Farms

Salci, Sener and Jenkins, Glenn

Queen's University - Canada, University of Birmingham - UK, Eastern Mediterranean University - North Cyprus

April 2016

An Economic and Stakeholder Analysis for the Design of IPP Contracts for Wind Farms

Sener Salci*

Department of Economics, Queen's University, Kingston ON, Canada
University of Birmingham, Birmingham, UK
ssalci@econ.queensu.ca

and

Glenn P. Jenkins

Department of Economics, Queen's University, Kingston ON, Canada
Eastern Mediterranean University, Famagusta, North Cyprus
jenkins@econ.queensu.ca

Abstract

In this paper we introduce a method for quantifying the benefits and costs of implementing a grid-connected onshore wind project that is owned and operated by an independent power producer (IPP). The proposed policy analysis tool is applied to the appraisal of a wind farm in Santiago Island, Cape Verde. The policy analysis is conducted from the perspectives of the electric utility, the country's economy, the government and the private sector investor. The key question is whether the design of the power purchase agreement (PPA) will yield a high enough rate of return to the project to be bankable, while at the same time yielding a positive net financial and economic present value to the electric utility and the country respectively. The PPA results in a negative outcome for the economy of Cape Verde in almost all circumstances. In contrast the owners of the IPP are guaranteed a very substantial return for their modest investment under all circumstances.

Highlights

- Financial, Economic and Stakeholder Appraisal of onshore grid-connected wind farm project
- Located in Cape Verde with very high fuel prices for electricity generation
- Power purchase agreement has fixed price path for wind electricity sales
- Risk of future fuel prices borne by Cape Verde
- All stakeholders expected to lose except for foreign IPP

Keywords: electricity, wind power, power purchase agreement, public–private partnership, Santiago (Cape Verde)

JEL Classification: D61, E22, Q42, L94, O55

* Corresponding author: 94 University Avenue, Dunning Hall, Department of Economics, Queen's University, Kingston, ON,K7L 3N6, Canada / ssalci@econ.queensu.ca

1. Introduction

The focus of this paper is the economics of onshore wind energy and the design of appropriate power purchase agreements (PPA) for such investments in isolated power systems. The role of the private sector in undertaking renewable energy projects has greatly increased over time (World Bank, 2013).[1] With the increased integration of renewable energy sources using public–private partnership (PPP), electricity sector regulators have had to devise new regulatory policies. It is common practice in developing countries for state-owned electric utilities to sign long-term PPAs with private electricity generators with the objective of making the projects bankable (Eberhard and Gratwick, 2013; Garcia and Meisen, 2008; Lesser and Su, 2008; Weisser, 2004)[2].

To assess the economic welfare impacts of a grid-connected wind farm project, one needs to learn from the appraisal how alternative designs of PPA and the overall PPA arrangements affect the allocation of benefits and costs for each of the stakeholders. In this paper, a clear distinction is drawn between the economic analysis and the financial analysis or, expressed differently, between the evaluation of public benefits and costs versus private benefits and costs[3]. The second aspect is to evaluate such an investment from the perspectives of the different market players. These include the public electric utility, the private investor, the economy and the government budget (Jenkins et al., 2011a).

The results of such an integrated analysis provide the information needed to improve the design of such arrangements so that a sustainable outcome is realised. In this paper, the impacts of

[1]World Bank Database for Private Participation in Infrastructure Database, including investments in electricity sector. Up-to-date country data is available at: http://ppi.worldbank.org/resources/ppi_glossary.aspx
[2] While developing countries are experiencing transition in private sector opening of their electricity markets, it appears to be very problematical, however (e.g. Phadke, 2009; Karekezi and Kimani, 2002).
[3] Some studies evaluated the economic viability of wind farm projects assuming such investments are made by utility. Therefore, estimation of the social cost of wind investment is expressed as capital, operation and maintenance costs net of avoided fuel and environmental costs enabled by the facility (e.g. O'Malley, 2007; Kennedy, 2005).

adding grid-connected onshore wind power are investigated in the context of the installation made on the island of Santiago, Cape Verde. The wind farm has been built by a foreign-owned independent power producer (IPP) who signed a long-term PPA contract with the public utility. Although the proposed framework is applied to the situation in Cape Verde, the model can be used for any isolated power system that uses similar contractual arrangements to acquire such renewable investments. This power system is typical of island economies and the smaller countries of Africa, Asia and Latin America (Alves et al., 2000; Deichmann et al., 2011).

2. Energy Power Profile of Santiago, Cape Verde

Cape Verde is a lower-middle-income archipelago in the central Atlantic Ocean off the west coast of Africa, with a total population of 503,600 spread over ten islands (World Bank, 2015). Santiago is the largest, with about 60% of the total population of the country living there (AfDB, 2014). As of 2014, the nominal GDP per capita in Cape Verde reached $3,715 (World Bank, 2015). The electricity coverage is almost 100% in urban areas, and is 84% in rural areas, where 35% of the total population lives (IEA, Africa Energy Outlook, 2014). The Cape Verde electricity network is composed of isolated electricity grids on each island without any interconnection between them. The public electric utility company, ELECTRA, is responsible for generation, transmission and distribution of electricity.[4]

The high cost of electricity generation, frequent black-outs and high energy losses have created a barrier to sustaining higher economic growth in Cape Verde (AfDB, 2014; Briceño-Garmendia and Benitez, 2011; Eberhard et al., 2008; Foster and Steinbuks, 2009; Oseni and Pollitt, 2013;

[4] ELECTRA is also responsible for the water supply on some islands of Cape Verde, including Santiago.

World Bank, 2011).[5] In response to both the deterioration of ELECTRA's capital assets and the need to meet the ensuing increased demand for power, the government of Cape Verde has initiated a long-term investment plan for the generation, transmission and distribution of electricity. As a first step, the national government implemented a series of rehabilitation projects with financial support from international organizations (World Bank) and regional banks (African Development Bank and the European Investment Bank). Investments were undertaken to increase the reliability of the power supply through reductions in energy losses and the frequency of black-outs. These investments have included transmission/distribution lines, substations and network upgrades.[6] Another purpose of extending the transmission lines to isolated loads is to increase the potential for fuel switching, as these isolated loads were being supplied by small, expensive and polluting diesel generators (World Bank, 2011). Alongside investments in renewables and grid infrastructure, ELECTRA also undertook to switch fuels from the more expensive heavy fuel oil (HFO) 180 to a less expensive HFO 380 (World Bank, 2011). These new and rehabilitation investments in generation, transmission and distribution will eventually allow ELECTRA to take advantage of economies of scale in generation by operating a small number of centralized power stations.

The stated objective of the government is to supply about 50% of the total electricity supplied solely through private sector investments in renewable electricity generation plants by 2020 (European Commission, February 2014). Investments in grid-connected onshore wind farms have been perceived as way to reduce the costs of thermal generation and to insulate electricity tariffs from the variability of oil prices. Owing to the quality and strength of the wind speed

---

[5] The 2011 estimates reveal that hidden costs included distributional losses, under-pricing and uncollected energy costs, and accounted for approximately 2% of the country's GDP (Briceño-Garmendia and Benitez, 2010). Therefore, the electricity supply costs incurred by the utility cannot be covered from consumers' bills paid to it.

[6] See African Development Fund Electricity Transmission and Distribution Network Development Project, available at http://www.afdb.org/fileadmin/uploads/afdb/Documents/Environmental-and-Social-Assessments/Resume_PGES_CaboVerde_DevelopReseauTransportDistribution_ORQR_final-_EN.pdf

across the islands and the high delivered costs of petroleum products, Cape Verde is potentially a very favourable location for electricity generation investments powered by wind (Cabral et al., 2009; InfraCO, n.d.; Lundsager and Hansen, 2002; Ranaboldo et al., 2014). To illustrate this, the average annual wind speed at a height of 70 m is 9 m/s and is very stable during most of the year (Cabral et al., 2009). In addition, the average daily solar irradiation level in Cape Verde is about 6 kWh/m^2 (Ranaboldo et al., 2014). The high solar irradiance level on the islands allows residential, hotel and industrial users to utilize it for water heating. Such solar applications contribute to the reduction of fuel use for electricity generation and potentially reduce the overall peak demand on the grid.

Previous studies have argued that the integration of a major wind farm into the power supply on Santiago would be economically viable. For example, based on their estimates of the capital costs, Cabral et al. (2009) concluded that a 5.1 MW grid-connected utility scale constituted a good investment for Cape Verde. Norgard and Fonseca (2009) studied the technical utilization of grid-connected utility-scale wind integration into the energy systems of Cape Verde's islands as a function of the wind capacity. Based on their technical study and the characteristics of the energy system on Santiago, they argued that a share of wind of up to 21% of the total generation can be produced and transmitted to the national grid without any losses. They further concluded that the avoided fuel savings from diesel plants alone justify the installation of wind farms in Cape Verde, including on Santiago. A World Bank study for Cape Verde suggested that wind-based sources of electricity generation will not provide firm generation capacity on Santiago, so that the integration of wind will not enable any reduction in thermal capital expenditures in Cape Verde (World Bank, 2011, p. 9). As a consequence, wind sources of electricity generation are limited in their substitutability for conventional thermal generators and cannot meet the entire demand for energy due to their uncontrollable variability.

A major problem with the Cabral et al. (2009) study is that the wind investment capital costs are assumed to be only $1.1 million per MW of wind capacity, which is much lower than the actual capital costs associated with such onshore wind investments. Furthermore, the studies by Cabral et al. (2009), Norgard and Fonseca (2009) and the World Bank (2011) do not take into account the actual electricity system supply and demand conditions of Cape Verde when evaluating the economic feasibility of wind farm investments. Finally, they do not carry out their financial and economic appraisal of the feasibility of electricity generation using a wind farm that is built and operated through an IPP.

An additional factor in the investment planning of the electricity sector of Cape Verde is that the volume of energy losses owing to low infrastructure quality is a major concern, particularly in Santiago. As of 2009, energy losses from electricity generation were 26.1% in ELECTRA's power operations in Cape Verde (Briceño-Garmendia and Benitez, 2011). This means that only 73.9% of generated electricity is actually distributed to existing customers – that is equivalent to 137 GWh out of 185 GWh total electricity generation in 2009. Economic costs of energy losses are enormous in Cape Verde such that losses in firms' annual sales revenue from power outages account for 8% of total potential revenue, as compared to 0.8% in middle-income countries (Briceño-Garmendia and Benitez, 2011). This means that considerable cost savings are possible from improving the performance of the existing transmission and distribution systems.

3. Methods

3.1 Screening Curve Analysis "with" and "without" Wind Integration

The economic value of a renewable energy source depends heavily on the time when it is produced, the wind intensity, its degree of penetration in the system (Holttinen et al., 2011;

Touhy et al., 2009), and the characteristics of the supply mix, such as fuel mix and system flexibility, correlation between renewable energy source and system load, and forecast error in wind (Bode, 2006; Denholm and Han, 2011; Hirst and Hild, 2004; Lew et al., 2011; Lund, 2005; Lund and Munster, 2003). This is why, in the load duration curve analysis, the wind power supply is best treated as a negative demand, since its output is intermittent and not dispatchable. To do this, one simply subtracts the electricity produced by the wind generators from the total system demand in each hour to give net demands that form a new annual load curve[7]. Over the year, the amount of electricity generated is given by the period-by-period wind capacity factor multiplied by the total installed nominal wind capacity, as expressed in equation (1).

$$q_{wht} = \sum_{w} CF_{wht} \cdot K_{wt} \qquad \forall ht \qquad (1)$$

where h refers to the time demand blocks of the year (off-peak, mid-merit, peak), t is planning years (t,…,T), w is wind turbine, q_{wht} is total MW wind power generated from each wind turbine (w) at hours h of time t, CF_{wht} is the capacity factor the of wind turbine at hours h of time t (%) and K_{wt} is wind turbine capacity MW at time t.

The net of wind generation load duration curve depends on the wind capacity installed, the technical availability factor of the wind farm, and the quality and intensity of the wind at any moment. These factors, in turn, determine the capacity factor of the wind farm within the project site (i.e. wind farm site).[8] Demand and supply have to balance every second, so the remaining

[7] Screening curve analysis approach simplifies the analysis of the intermittency of electric power from renewables. See, for example, Kennedy (2005), Lamont (2006) and George and Banerjee (2011) for a similar approach.

[8] The availability factor directly relates to the technical point of view and describes the ability to operate the wind farm safely. The capacity factor of wind turbines is a function of the wind speed in the area of construction of the farm and the power curve of the particular wind turbines constructed. Therefore, the capacity factor is the key parameter that actually dictates the amount of electricity that can be produced by the wind turbine.

demand for electricity (residual load) has to be supplied by the thermal generators. Wind power is therefore an exogenous variable in our analysis. This can be expressed as follows:

$$D_{ht}^{n} = D_{ht}^{g} - q_{wht} \qquad \forall ht \qquad (2)$$

where D_{ht}^{n} is demand <u>net</u> of wind capacity (equivalent of total supply of electricity from thermal generators) and D_{ht}^{g} is demand <u>gross</u> of wind capacity at block h in MW. From equation (2), the demand for electricity that the conventional system must meet (D_{ht}^{n}) is the total demand less the quantities supplied by wind generation.is the net of wind quantities such that:

$$\sum_{z} q'_{zht} = D_{ht}^{n} \qquad \forall ht \qquad (3)$$

where q'_{zht} is MW conventional electricity supplied by plant z "with" wind integration at hours h of time t and D_{ht}^{n} is total MW residual demand for electricity at hours h of time t.

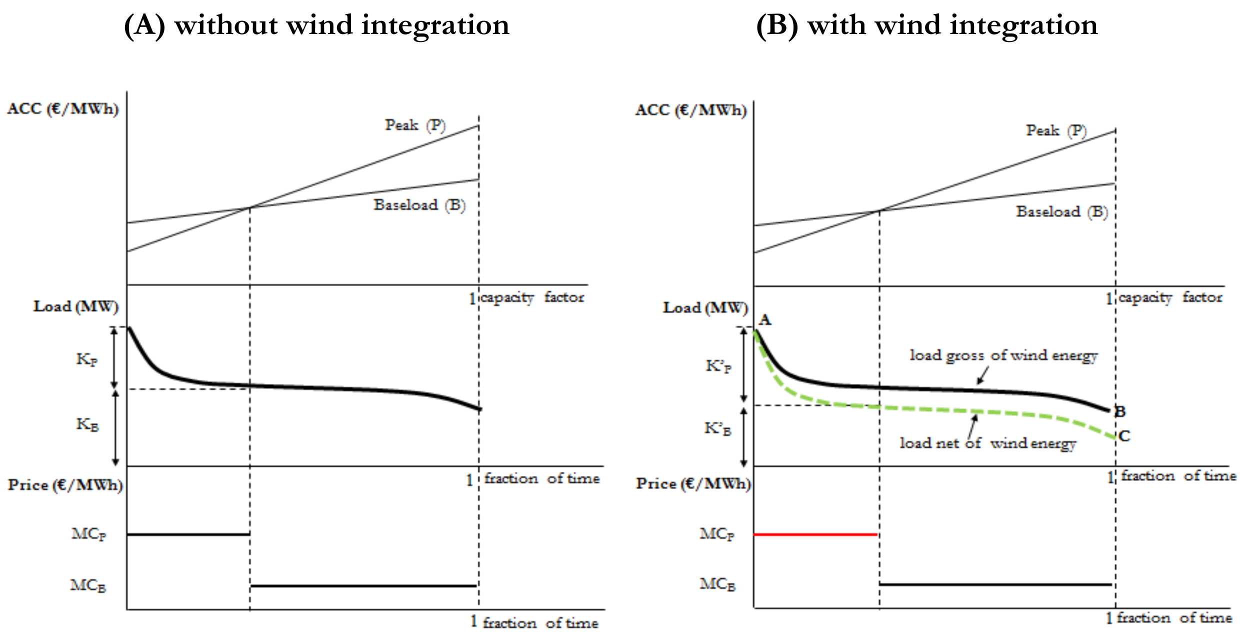
From equations (1) to (3), the wind power output can be expressed by the following equation:

$$\hat{q}_{wht} = \sum_{z} \left(q_{zht} - q'_{zht}\right) \cdot l_{ht} \qquad \forall_{ht} \qquad (4)$$

where $\hat{q}_{wht}$ is wind electricity supplied at hours h of time t, q_{zht} is conventional electricity supplied by plant z "without" wind at hours h of time t, q'_{zht} is conventional electricity supplied by plant z "with" wind at hours h of time t, l is load (e.g. peak demand, off-peak demand load) and l_{ht} is the number of hours (duration) in each demand load l at time t.

In Panel B of Figure 1, the area ABC represents the sum of the reduced electricity generation in MWh from each type of thermal power generation that is brought about by the introduction of the wind facility into the system. Santiago's power system is small enough to allow one simply to rank the generators from the lowest to highest marginal running cost. If the installed amount of wind power penetrates the system, an analysis of the optimal power mix "with" wind must be carried out in order to derive the costs and benefits of wind power. Comparing Panel B with Panel A in Figure 1, the optimal power mix "with" the wind generation will necessitate a larger proportion of peaking capacity $\left(K'_P > K_P\right)$ than would be the case without the wind farm.

Figure 1. Long-Run Impacts of Wind Capacity Integration on System Scheduling and Planning



In deciding the capacity and the year of investment, both the growth in the demand for electricity and system reliability are considered. The peak demand for electricity generation capacity is expected to grow as fast as the overall growth in energy demand in Cape Verde. In order to minimize the total generation costs a simulation program was used that reflected the fixed and variable costs of electric utility[9]. These are the sum of the discounted fixed and variable fuel costs subject to the set of constraints, including deterministic demand balance net of deterministic wind quantities and the output constraints of each plant. Wind power is examined in terms of the way it is used as supplementary or substitute for generation from conventional thermal power plants. The wind turbines are introduced into a conventional power grid with multiple sources of diesel generation capacity running with fuel oil and diesel oil. Thus, the annual MWh of energy displaced by the wind turbines is estimated based on simulation results. These values from simulations are used to evaluate the feasibility of the wind farm investments.

3.2 An Integrated Investment Appraisal Framework

An integrated investment appraisal framework incorporates financial, economic and stakeholder impacts of the investment project with a single cash/resource flow model of the investment[10]. This framework includes both an economic impact analysis and a distributional assessment for each of the impacted groups, namely the IPP, the electric utility, the country's economy and the national government budget. Hence, the integrated appraisal framework allows us to determine who picks up the benefits and costs of this private IPP wind electricity investment. This, in turn, allows us to re-allocate (re-distribute) the benefits and costs according to the provisions of the PPA.

The financial analysis component of the integrated investment appraisal framework gives the results for both the private wind power supplier and the public utility. The economic analysis yields the results for the country's economy, an externality analysis for the government of Cape Verde and for the global economy. The riskiness of all project variables that may potentially

[9] The simulations are carried out using General Algebraic Modeling System (GAMS) programming software.
[10] For details, see Jenkins et al. (2011a, 2011b).

affect the viability of the project can be tested and their impacts on each stakeholder evaluated in a consistent fashion to allow better management/distribution of the risks associated with the project. In this way, regulators can link renewable energy investments and relevant energy policies in such a way as to benefit both the economy and utilities while allowing private investors to earn a fair return on their investment.

The IPP's Point of View

Unlike the situation for the thermal electricity generation operations, the private investors who own such wind farms incur low variable costs (mostly operating and maintenance costs, O&M) to generate electricity, but face very substantial capital costs (Krohn et al., 2009). Since the capital costs are known, the objective of a long-term PPA is to reduce the risks of the operation and to provide a stable stream of revenue to the IPPs to cover their operating and maintenance (O&M) and financing costs (Burer and Wustenhagen, 2009; Weiss and Sarro, 2013; Wiser and Pickle, 1998).

Both the MWh of the electricity supplied from wind turbines and selling price per MWh of power are pre-determined with PPAs. The price of energy per MWh may also be adjusted for inflation or an agreed fixed rate of price escalation to account for movements in the price level over time. Thus, the revenues of the IPP are secured and the market risks for the private investors are removed, with the exception of the risk associated with their O&M costs (Baylis and Hall, 2000; Jensen and Stonecash, 2005; Lock, 1995). The financial viability of the wind power project for the IPP is estimated by deducting the costs of capital, O&M costs and taxes from the revenues from wind power sold out to the public utility. An additional source of revenue to the IPP is from the sale of the carbon credits that it receives for implementing this wind power project. The financial cash inflows, outflows and net present value (NPV) from the perspective of the IPP can be expressed as in equations (1), (2) and (3) in the Appendix.

The State-Owned Electric Utility Company's Point of View

From the public utility's perspective, the actual incremental benefits of having an IPP investing in wind turbines is the lower fuel consumption that results from the sum of the reduced power generation from the conventional thermal generation plants. These thermal generators are heterogeneous in terms of their characteristics, such as age, type and amount of fuel used and the load factor. Fuel savings from individual thermal plants are therefore directly dependent on the MWh amount of electric power actually displaced from each conventional thermal generator by the power supplied by the wind energy. The payment amounts to the IPP are made on the basis of the MWh of power supplied by the wind farm in a given year. They are calculated without considering the type and time of displacement of power from conventional generators. In short, the net annual savings of the electric utility are estimated by the financial value of fuel and fixed cost savings minus the financial payments made to the wind power generation.

In PPP-type renewable investments, all investment costs associated with the wind farm will be paid for by the foreign IPP, but the public utility pays for the additional investments needed in new transmission lines to connect the wind farm to the national grid and maintain reliability with wind integration (Karki and Billinton, 2004; MacCormack et al., 2010). The financial cash flow and the NPV from the perspective of the state-owned utility company can be expressed as in equations (4), (5) and (6) in the Appendix.

The Country's Economy's Point of View

The economic costs and benefits resulting from wind turbine investments are different from the financial benefits and costs due to tax distortions in the markets. The financial benefits and costs of the project to the Cape Verdean economy are adjusted for taxes and distortions to arrive at their economic values to the country, as we carry out quantitative economic analysis from economic prices, not market prices. The economic benefits of the wind project that accrue to the country are basically fuel savings and the taxes levied on the revenues that the IPP receives from the carbon credits. When moving from the financial analysis of fuel savings to the economic analysis of fuel savings, a fuel oil specific conversion factor is used to estimate the savings in fuel from a country's economy point of view[11]. In addition, any excise taxes levied on the value of the carbon credits are added to the economic benefits generated from the wind project on Santiago, as they are a net inflow of resources to the country.

The social cost of carbon saved through electricity generation by wind does not enter into economic analysis because the carbon credits earned by the project allow external generation elsewhere to produce more CO_2 emissions. Hence, the economic benefit from CO_2 emission reduction is the marginal resource costs saved by the entity abroad that is willing to buy the carbon credits. Therefore, the global economic value of CO_2 reduction by Cape Verde is fully captured by the price of the carbon credits. These do not accrue to Cape Verde because they are paid to the foreign IPP. On the economic costs side, the financial payments as stipulated by the PPA for each of the MWh of electricity supplied by the foreign IPP are made in foreign currencies. Hence, these payments must be increased by the foreign exchange premium (FEP) to estimate the economic costs paid to the host country[12]. The economic resource inflows, outflows and NPV can be expressed as in equations (7), (8) and (9) in the Appendix.

[11] The import duties and VAT on fuel oil will cause the financial price to be greater than its economic cost, while the existence of a foreign exchange premium will increase its economic cost. The net effect in this particular case is to cause the economic cost to be less than the financial price of fuel oil.

[12] FEP captures all domestic and international taxes and distortions associated with tradable items, so it captures the changes in welfare in a country from foreign exchange payments that are paid to the foreign private investor (Kuo et al., 2015).

Externality Analysis[13]

A stakeholder impact analysis is also carried out. There are some externalities associated with the economic activity (project) that cause the economic benefits and costs to be different from the financial benefits and costs. The difference between the economic resource flow and financial cash flow represents the tax and other externalities associated with the wind project in question. The tax externalities created by the wind farm project are identified and quantified. The stakeholder analysis of a typical renewable project is conducted to identify which particular segments of society reap the project benefits and which ones, if any, lose from the implementation of that particular renewable project. The stakeholder analysis of any project builds on the relationship described in equation (5).[14]

$$EV = FV + \sum Ext_k \tag{5}$$

where EV is the economic value of an input or output in monetary terms, FV is the financial value of the same variable and $\sum Ext_k$ is sum of all the externalities that make the economic value different from the financial value of the item.

It should be noted that this statement is true only if the economic opportunity cost of capital (EOCK) is used to the count net cash flow for financial and economic analysis. The economic NPV and financial NPV will also differ due to the application of economic conversion factors and the FEP and NTP adjustments made on the financial benefits and costs. These account for the government fiscal impacts as part of the externalities. In other words, the economic value of an item can be expressed as the sum of its financial value plus the value of externalities (i.e. taxes,

[13] See notation described in Appendix.
[14] See Jenkins (1999).

tariffs, consumer/producer surplus). On the basis of equation (5) above, the following accounting relationship also holds, if a common economic discount rate is applied to all financial and resource flows:

$$NPV_{EOCK}^{CV} = NPV_{EOCK}^{EU} + \sum PV_{EOCK}^{GFI} \tag{6}$$

where NPV_{EOCK}^{CV} is the PV of the net economic benefits (country, CV) discounted by the EOCK, NPV_{EOCK}^{EU} is the PV of the net financial cash flow (electric utility) discounted by the EOCK and $\sum PV_{EOCK}^{GFI}$ is the sum of the PV of all the tax externalities (GFIs, government fiscal impacts) generated by the wind project.

In this case, GFIs arise in a number of ways. First, there is a reduction of tax revenues owing to the decline in petroleum imports. Second, the government collects taxes on the project's earnings from the sale of carbon credits. Third, because both the fuel saving and the PPA payments to the IPP involve foreign exchange, an FEP is applied to these offsetting resource flows. In this case, the FEP is simply the extra tax revenues that can be generated from the purchase of tradable goods and services when additional foreign exchange is acquired by Cape Verde. When foreign exchange is used by the project to make payments abroad, the premium reflects the indirect taxes given up by the country. There will be a loss in indirect tax revenue as fewer tradable goods and services can be now purchased by others. Rearranging equations (5) and (6) will yield the following relationship:

$$\sum PV_{EOCK}^{GFI} = NPV_{EOCK}^{CV} - NPV_{EOCK}^{EU} \tag{7}$$

where $\sum PV_{EOCK}^{GFI}$ is sum of the PV of all the tax externalities (GFIs) generated by the wind project, NPV_{EOCK}^{CV} is the PV of the net economic benefits (country, CV) by the EOCK and NPV_{EOCK}^{EU} is the PV of the net financial cash flow (electric utility) discounted by the EOCK.

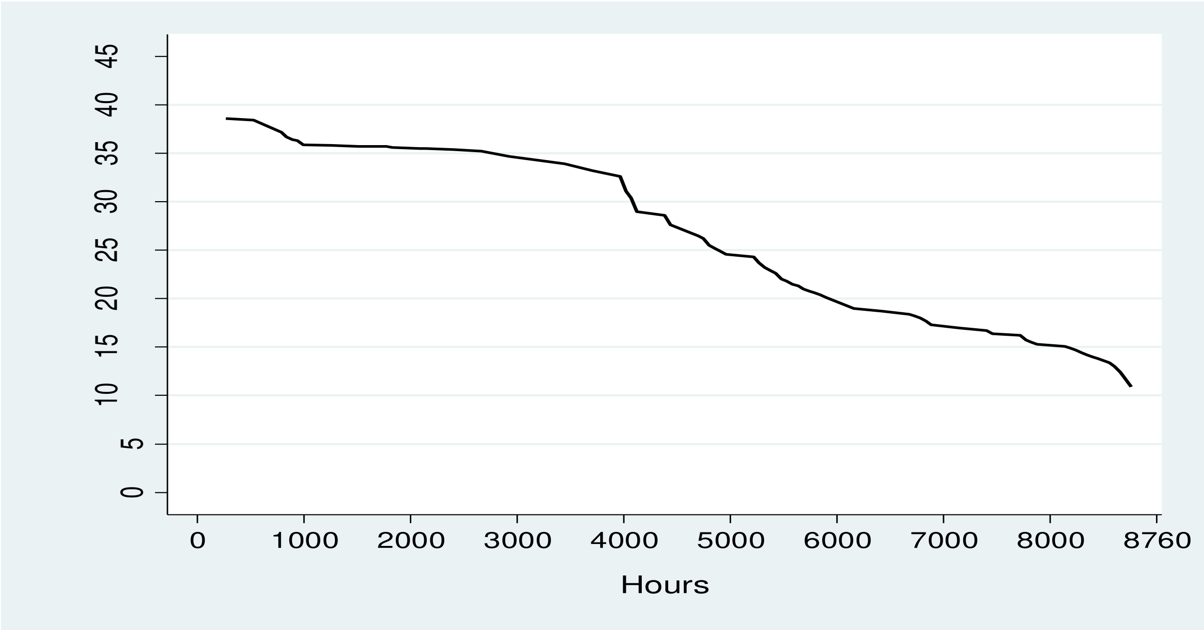
In summary, the GFIs are equal to the sum of the loss in tax revenues from reduced oil imports (−), the gain in the value of the FEP on fuel savings (+) and the loss in FEP due to the payments now made to the IPP (−), and the gain in excise taxes levied on the carbon credits received by the private operators of the project (+).

4. Data for Santiago Island of Cape Verde

The demand for electric generation in 2010 is presented in Figure 2. The amount of electricity that falls into the extreme peak load time is about 40 MW, which must be supplied over only 261 hours a year. It is expected that increasing population growth, the expansion of the service sectors, including real estate, tourism development and increased production of desalinated water will create strong growth in the demand for electricity.

Using Santiago's historical annual demand for electric energy in 2006 and a subsequent demand study for the island prepared for ELECTRA by Simonsen Associados (February 2008), the annual projected load duration curves from 2010 to 2031 are produced for the island. The demand for electricity is projected such that there is a 15.5% annual increase from 2007–2012, a 6.25% annual increase from 2013–2017, a 5% annual increase from 2018–2022, a 4.75% annual increase from 2023–2027, and a 4.5% annual increase from 2028–2031. Therefore, the focus of this research is entirely on the supply side of the power system. The demand side is simply assumed to follow this set of projected growth rates.

Figure 2. Annual Load Duration Curve of Santiago Island of Cape-Verde in 2010



Source: Reproduced from data supplied by Simonsen Associados (February 2008)

The existing power supply mix of the island in 2012 includes diesel generators running with fuel oil and diesel oil. Cape Verde has some of the highest transportation costs for fuels of any jurisdiction in the world. For instance, the domestic fuel oil costs for electricity generation are about 50% more than the world price as a result of transportation costs and taxes and other charges. The power supply and fuel characteristics of the existing system are provided in Table 1 with each power plant's year of establishment (t), MW available capacity, type of fuel and amount of fuel oil requirements to generate each kWh of electric output. As expected, the generation plants are heterogeneous. Thus, the operating costs and emissions from individual power plants for each MWh of electricity are not the same because of differences in their type and amount of fuel consumption.

A 1% annual increase in fuel requirements for electricity generation by any existing or new power plants added to the system is assumed, owing to the degradation of the plant, which starts after the first year of operation. Similarly, there will be a 1% annual decrease in fuel requirement for new power plants until the time of operation as a result of technological advancement. Both parameters are assumed to be only a function of time. Furthermore, it is assumed that all candidate power plants are running with heavy fuel oil and also that tax and other charges paid on fuel and fuel transportation will not change throughout the project's life.

Table 1. Diesel Generator Capacity and Fuel Characteristics of Santiago Island Grid in 2012

Generator	Year Commissioned	Capacity (MW)	Type of Fuel Used	Fuel Consumption (litre/kWh)
Palmarejo III	2011/2012	22	HFO	0.206
Palmarejo II	2008	14.9	HFO	0.213
Palmarejo I	2002	11.2	HFO	0.220
Prai II	1992	5.1	Gasoil	0.207
Prai I	1987	2.4	Gasoil	0.206
Assomada	2006	3.9	Gasoil	0.230
Tarrafal	1995-200	1.4	Gasoil	0.244
S. Cruz	n.d.	2.2	Gasoil	0.236
Total		**62.9**		

Source: Annual Report, 2012, Energy Regulatory Agency of Cape Verde (www.are.cv)

The *Cabeólica* onshore wind farm project[15] is a PPP between the government of Cape Verde, the electric utility (ELECTRA) and a foreign private sector investor (InfraCO). The wind power project is owned by the foreign-owned IPP, which is responsible for installation, operation and maintenance of the wind farm. The electric utility is the off-taker of the generated wind electricity. The wind farm is located in the southern part of Santiago, near the city of Praia, and occupies 30 hectares of land that is rented at a fixed rate per year by the project from the local municipality. The wind farm started its operations at the beginning of 2011 and is expected to continue until the end of 2030. It was implemented on the basis of a 20-year PPA. With the

[15] For more information about *Cabeólica* onshore wind farm project, see UN, Clean Development Mechanism (2012) and InfraCO (n.d).

completion of the wind project, the private IPP installed 11 onshore wind turbines, each with a generation capacity of 0.85 MW, yielding 9.35 MW of installed wind capacity into the existing system in Santiago. This total installed wind capacity is expected to generate, in the early years, 25% of the island's energy needs (InfraCO, n.d.). The wind farm is connected to the island's power grid by transmission lines, which need to be installed. The public utility is responsible for the transmission as well as the distribution of power to the existing users on the island.

The technical availability factor of the wind turbines is assumed for the purpose of this analysis to be 100%, with an average annual load (capacity) factor of 40% for the wind farm at all times and for all demand blocks. For the sake of simplicity and owing to wind speed data constraints, the availability factor and capacity factor of the wind turbines are assumed to be the same throughout the life of the project and represented by PPA volumes. The penalty or compensation payments may also occur during the project operation time. The penalty payment is made by the private sector if it cannot supply the power, and the compensation payment is made by the public utility when the private IPP supplies more wind power than is stated in the contract. In our analysis, the power from wind is assumed to be supplied successfully such that the system is flexible enough to cope with wind power variability. Therefore, we assume that the IPP will continuously supply electric power without any technical problems. The revenues from wind power generation are subject to the pricing scheme of the PPA.

Revenues of the foreign IPP are based here on an assumed PPA tariff that is agreed upon between the private supplier and public utility before the implementation of the project. Based on the PPA, the wind project is contracted for 20 years and the wind energy tariff has two components: a fixed portion and annual escalation factor. Based on PPA, the utility will pay a fixed tariff at 120 €/MWh for energy. This rate is subject to a fixed escalation factor of 3.5% per year for the duration of the contract (UN, Clean Development Mechanism, 2012). Because the private sector will generate a green source of electricity, it will also earn carbon credits from the Clean Development Mechanism (CDM). The base for calculating the €/MWh carbon credits is the quantity of CO_2 expressed, since electricity production is calculated in MWh. The conversion factor for carbon (ρ) is given by 0.9049 tCO_2/MWh and the carbon price/tonne is assumed to be the rates offered by the CDM (2006, p. 27), which are 15 €/tonne until 2013 and 10 €/tonne after 2013. We assume these carbon payments will be paid throughout the project lifetime. The annual earnings of the IPP from carbon credits are subject to a 7.5% excise tax collected by the government of Cape Verde.

Table 2. Capital and O& M Costs of Installed Wind Capacity in Santiago Island, 2010[16]

Investment Costs	(€ millions)
Equipment, procurement and construction (EPC)	15.2
Contingency	1.1
Land	0.35
Development	1.00
Total capital costs	**17.3**
Fixed operating expense*	
O& M - % of wind farm investment	1
Total Investment Costs (million €/MW)	2.3

Source: United Nations, UNFCCC, CDM, July 2006, p.14. (*) Lundsager and Hansen (2002).

The capital costs of the project are assumed to be disbursed in two periods: 50% at the end of 2010 and the remaining payments at the end of 2011. The capital and O&M expenses of the wind project are presented in Table 2. In our empirical estimates, we assume that non-fuel operating costs for the rest of the electric utility do not increase when the wind farm is integrated into the system, but in reality they will increase (Lamont, 2006). Furthermore, we assume that there are no negative externalities associated with wind power itself.

[16] For analysis, we converted all USD ($) monetary variables into Euro (€). The exchange rate between $/€ is 1.28 in 2010. Real exchange rate appreciation/depreciation factor is assumed to be 0% throughout the project.

While evaluating the feasibility of the wind farm project, a single real rate of discount (net of inflation) of 10% is used for the cost of capital to both the IPP and the country throughout the project life. For economic analysis, the FEP for Cape Verde is estimated as 10% (Kuo et al., 2015) and the economic conversion factor for oil is calculated to be 0.99. Incorporating the demand for and supply of electricity and wind parameters (both financial and economic), NPVs are estimated to show the beneficiaries and losers from the wind power project. We also test the impacts of the key variables, including price of wind energy, fuel price and expected capacity factor for the wind generation that would make electricity generation by wind turbines financially and economically feasible. The empirical results for Santiago illustrate how a set of estimates of the costs and benefits can be distributed between the public utility, the IPP, the economy and the local government.

In our analysis, we estimate the revenues from gas emission reductions for the private sector participants and tax gains from emissions reductions for the economy of Cape Verde and the local government. The private sector will potentially earn more if it is able to sell carbon credits at a higher price, but global emissions from electricity generation will not be reduced.

4. Results and Discussion

Using the integrated framework, equations (1 to 9), in Appendix A.2, the net impacts of the *Cabeólica* wind farm project on the Santiago island grid are quantified and distributed to find the viability of the project from each point of view. These results are presented in Table 3, 4 and 5. As a first step, the actual PPA price at 120 €/MWh is used to evaluate the feasibility of the wind farm project for each stakeholder.[17] Based on this PPA price, we find (Table 3, row 5) that the

[17] The pricing of renewable power is subject to financing parameters and sensitive to financing arrangements of IPP investments, market and non-market (e.g. political risks), involved in its investments and strongly affects the distribution of project benefits and costs. See also similar cost-based approach for tariff setting in renewable projects

NPV accruing to the foreign IPP is €14.8 million. This is a substantial return to the owners of the project given that the total investment cost of the project is just €17.3 million. The net loss to the electric utility is €2.3 million; the net loss to government tax revenues is €3.2 million, while the net loss to the entire economy of Cape Verde is €5.5 million. As reported in Table 3, row 1, the actual PPA price of wind energy is twice the break-even of PPA price of 60 €/MWh that would leave the foreign IPP with a zero NPV or 10 percent real rate of return.

Table 3. Impacts of PPA wind energy tariff (NPV values in million €)*

Perspective / PPA tariff (€/MWh)		Foreign IPP	Electric Utility	Government Budget	Cape Verde Economy
1.		**2.**	3.	4.	5.
1.	60	**0.00**	13.356	−2.376	10.980
2.	80	4.539	8.550	−2.626	5.924
3.	100	9.858	2.919	−2.919	**0.00**
4.	110	12.615	**0.00**	−3.071	−3.071
5.	**120**	**14.764**	**−2.276**	**−3.189**	**−5.465**

Source: Authors' own calculations.
(*) NPVs are evaluated at 10% real discount rate, heavy fuel oil price at $60/barrel and wind capacity factor at 40%. In each case, the 3.5% annual escalation is used as specified in the PPA for Cape Verde.

The break-even PPA prices that make the country and the utility indifferent between generation from the wind farm or by its generation plants would be approximately 100 €/MWh and 110 €/MWh, respectively, Table 3, rows 3 and 4. These prices are well above the 60 €/MWh which makes the NPV of the IPP equal to zero. If the PPA price of wind-generated electricity were lowered to 80 €/MWh, all stakeholders would be better off with the implementation of the project, except for the national government (Table 3, row 2).

in the USA, CREST Model, *Renewable Energy Cost Modeling: A Toolkit for Establishing Cost-Based Incentives in the United States*, National Renewable Energy Laboratory, US Department of Energy.

As stated previously, the government is planning a shift from HFO 180 to HFO 380 starting from 2015, because importing HFO 380 is cheaper for Cape Verde (World Bank, 2011). Benefits for the electric utility and the economy of the country from the implementation of the wind farm project come mainly from fuel cost savings, so heavy fuel oil prices for electricity generation are also a key parameter in the feasibility of wind farm projects. Therefore, we test for the impact of changes in the world price of HFO 380 on the public utility and the economy of Cape Verde.[18]

In Table 4 column 2 we find that the net gains of the foreign IPP do not change with fuel price changes, as both quantities and prices are guaranteed before the implementation of wind investment. On the other hand, we see in columns 3, 4 and 5 that fuel price changes greatly affect the cash flow statement of public utility, the economy of Cape Verde and the national government. While it is often stated that such renewable electricity generation technologies reduce the risk to the country of changes in petroleum prices we see from the results that this is clearly not the case. The electric utility and economy of Cape Verde bear the risks of oil price fluctuations. The only difference is that with such a renewable generation investment it is the value of future benefits that are at risk instead of future generation costs.

Based on the empirical results, we find in Table 4, row 1 that at a world fuel price of $60/barrel, the net loss to the electric utility is €2.3 million, the net loss to government tax revenues is €3.2 million and the net loss to the economy of Cape Verde is €5.5 million. Because the wind farm is saving fuel, as the fuel price increases the net loss imposed by the wind farm on the electric utility and on the economy decreases. As fuel price risk is entirely borne by the economy and the utility, such wind investments can only be viable with an expectation of higher fuel prices. In this case, the break-even world price of heavy fuel oil that makes the utility and economy of Cape Verde

[18] This is average world price from 2010 to 2015. The delivered price of heavy fuel oil for electricity generation in Santiago is approximately 50 percent higher than the world price of $120/ barrel.

indifferent between generation from the wind farm or by thermal generation would be approximately $70/barrel for the utility and $80/barrel for the economy. These prices are above current heavy fuel oil prices[19,20].

Table 4. Impacts of World Price of HFO (NPV values in millions €)

Perspective / Fuel Price ($/barrel) *		Foreign IPP	Electric Utility	Government Budget	Cape Verde Economy
1.		2.	3.	4.	5.
1.	**60 (95)**	**14.764**	**−2.276**	**−3.189**	**−5.465**
2.	68 (100)	14.764	**0.00**	−3.324	−3.324
3.	70 (105)	14.764	610	−3.360	−2.750
4.	80 (120)	14.764	3.533	−3.533	**0.00**
5.	90 (135)	14.764	6.382	−3.701	2.681

Source: Authors' own calculations.

(*) In column 1 the first price is the world price per barrel of HFO380 and the values in parenthesis are approximate prices for the fuel delivered to generation sites in Cape Verde. NPVs are evaluated using a 10% discount rate, the PPA energy tariff is held at 120 €/MWh and wind capacity factor is assigned to be 40%.

With the stated wind investment costs, price of wind energy and fuel prices, there is a negative relationship between the wind capacity factor of the wind farm and the NPVs of the stakeholders, with the exception of the foreign IPP. These results are presented in Table 6. An increase in the wind capacity factor increases the amount of wind energy produced and sold, and, as a result, increases the revenue of the IPP. At a fuel price of $60/barrel, both the electric utility and the economy of Cape Verde will lose even more. At the low fuel prices, the additional fuel

[19]Although crude oil prices dropped sharply in mid-2014 down to below $50/barrel, recent crude oil forecasts released by the US Energy Information Administration (April 2015) and World Bank (April 2015) show that the US government expects the average annual oil prices will increase over time. For the complete EIA report, see http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf and for the complete World Bank report, see http://www.worldbank.org/content/dam/Worldbank/GEP/GEPcommodities/GEP2015b_commodity_Apr2015.pdf

[20] For real-time crude oil price data, see, for example, http://www.oil-price.net/. These are world prices, so exclude transportation and taxes paid by utilities. In our analysis, international and domestic transportation charges as well as taxes (both import tariff and excise tax) are added to the world prices of HFO in order to arrive at the financial cost of fuel for electricity generation in Cape Verde.

saving as a result of the higher capacity factor of the wind farm does not compensate for the additional MWh high energy payments paid to the foreign IPP. The tax losses of the government of Cape Verde also increase at the higher capacity factor, because the taxes paid by the IPP to the government are less than the taxes foregone from oil imports. Comparing Tables 5 and 6, we can clearly conclude that the wind farm project is feasible for the electric utility and the economy of Cape Verde only at high fuel prices. A higher wind capacity factor is good for the IPP but costly for Cape Verde's economy and the public utility.

Table 5. Impacts of Wind Capacity Factor (%) (NPV values presented in million €)*

Perspective / Wind Capacity Factor (%)		Foreign IPP	Electric Utility	Government Budget	Cape Verde Economy
1.		2.	3.	4.	5.
1.	30	6.481	−1.707	−2.413	−4.120
2.	35	10.622	−1.991	−2.801	−4.792
3.	**40**	**14.764**	**−2.276**	**−3.189**	**−5.465**
4.	45	18.906	−2.560	−3.577	−6.138
5.	50	23.048	−2.845	−3.966	−6.810

Source: Authors' own calculations.

(*) NPVs are evaluated at a 10% discount rate, a PPA Tariff of 120 €/MWh and a heavy fuel price of $60/barrel.

Within the range of wind capacity factors considered in this analysis, the change in private sector earnings is very sensitive to the capacity factor as compared to the change in earnings by the utility and the economy of Cape Verde. The private supplier takes more risk when a lower capacity factor of the wind farm is realized, while the utility takes the risk of there being a lower heavy fuel oil price after the implementation of the wind farm project.

6. Conclusions and Policy Implications

Using this integrated investment appraisal framework one can determine whether the wind project is bankable and will provide the necessary return for the foreign IPP. At the same time one can see the clear policy trade-offs that arise in design of such arrangements. For the utility and the country, the net benefits of the project are directly tied to the future world prices of petroleum fuels, the capacity factor of the wind farm and the PPA price of wind energy paid to the private sector supplier. Policy initiatives to expand the use of grid-connected utility-scale wind farms in Cape Verde are promising only if heavy oil prices increase substantially. Even though the cost of HFO delivered to Santiago Island is 50 percent higher than most places in the world, this wind farm investment creates losses for the economy at a likely range of world prices of HFO.

In the case of thermal electricity generation, fuel prices are likely to fluctuate over time. In some periods, fuel prices will rise, while at other times they will fall. Fuel price risk can go in either direction. For a generation by a wind farm, the utility and the country must settle on a PPA price of electricity beforehand that makes the project bankable. If the electricity price agreed to in the PPA allows the utility to purchase electricity at the same cost as it could supply electricity using its thermal plants, then if the petroleum prices fall the utility will be worse off. This arises because the PPA price is fixed and it must purchase all the electricity supplied the wind farm at that price. For the economy of Cape Verde, entering into this 20-year agreement with a wind farm is comparable to entering into a 20-year forward contract to purchase heavy fuel oil for thermal generation at a fixed real price of $80/barrel. The fact that no such long term forward contracts exist for any petroleum product is a testimony to the perceived riskiness of such contracts by the private sector.

While Cape Verde has reduced its risk exposure to fuel price increases above \$80/barrel, it has done this by forfeiting all the expected benefits from petroleum prices falling below \$80/barrel. If the real price of \$80/barrel is above the supply price that in the foreseeable future brings increased supplies of oil on to the market, this is essentially a bet against the effectiveness of the forces of demand and supply to maintain petroleum prices below \$80/barrel. The only participant in the deal who has had its risks mitigated is the private IPP. Even in the case of the IPP it faces the political risk of consumers demanding a renegotiation downward of the PPA price of electrical energy should the rest of the world be fortunate enough to enjoy lower petroleum prices. In the case of Cape Verde with its higher petroleum costs for electricity generation, where a world price of petroleum of \$80/barrel translates into a delivered price of \$120/barrel, still this IPP investment in a wind farm is a highly risky and fundamentally unattractive investment from the perspective of the consumers of electricity in Cape Verde who will be expected to pay the bills.

From the perspective of the government the wind electricity tariff should be a socially desirable tariff; that is to say, it must be at the lowest possible cost of supplying electricity. On the flip side, the price of wind energy must also yield a sufficiently high rate of return to the IPP so that these investments will still be attractive from the private owner's point of view and bankable from the lender's point of view. As of today, long-term contracts between the private sector investor and the electric utility (on behalf of the government) provide price certainty to the investors in renewable investments. This allows producers to increase their debt leverage and lower their financing costs. Based on the long-term contracts, the electric utility is obliged to buy wind electricity at a fixed price path for 20 years. This unloads most of the risks of the value of the future benefits from such investments onto the utility and the country.

The major concern of private sector participation relates to weak institutional and regulatory mechanisms (i.e. governance). Weak governance results in higher risks for such a IPP infrastructure investment and so increases the cost of both equity and debt financing of such projects – and hence the price of energy. Unlike many developing countries, Cape Verde has a relatively high governance index with respect to the quality of its institutions, including the rule of law, control of corruption and property rights (Worldwide Governance Indicators, World Bank, 2014). Hence, the contractual arrangements are highly credible from the perspectives of both the private owners and the lenders. In such a case, the financial and economic costs set in the PPA have a high likelihood of being paid by the utility and borne by the economy.

Appendix

A.1 Notation for Calculations in Section 3.2

Symbol	**Description**
EB_t^{CV}, EC_t^{CV}	economic benefits earned and costs paid by the country's economy from wind investments at time t, respectively (€)
$EOCK$	economic opportunity cost of capital (%)
EV	economic value of an input or output (€)
$\sum Ext_k$	sum of all the externalities created due to the project (€)
F_{wt}	fixed operating and maintenance expenses of wind farm in €/MW
F_{zt}	fixed operating and maintenance costs of installed existing thermal generators running in the system (€/MW)
FB_t^{EU}, FC_t^{EU}	annual financial benefits and costs of the public utility for wind integration (€)
FB_t^{IPP}, FC_t^{IPP}	annual financial benefits and financial cost of the IPP (€)
FEP	foreign exchange premium paid on international currency transactions (%)
FV	financial value of the same variable (€)
gp_{wt}	annual wind price escalation agreed by parties (%)
h	time demand blocks (off-peak, mid-merit, peak)
I_t	investment costs associated with wind investments in million €/MW
K_{wt}	total wind capacity installed in MW
K_{zt}	MW of thermal capacity from each plant "without" wind integration at time t
K'_{zt}	MW of thermal capacity from each plant "with" wind integration at time t
l_{ht}	number of hours of duration of load (e.g. number of peak hours, off-peak hours)

$NPV_{t=0}^{IPP}$	net present value of IPP in millions of € at 2010 price level
$NPV_{t=20}^{EU}$	net present value of electric utility (EU) in millions of € at 2010 price level
NPV_{EOCK}^{CV}	PV of the net economic benefits (country, CV) in millions of € at 2010 price level, discounted by the EOCK
NPV_{EOCK}^{EU}	PV of the net financial cash flow (electric utility) in millions of € at 2010 price level, discounted by the EOCK
p_{ct}	private costs of carbon credits earned from fuel replacement (€/MWh)
p_{wt}	fixed portion of wind energy price (€/MWh)
PF_{jt}^{f}, PF_{jt}^{e}	financial and economic cost of j type of fuel in period t, respectively (€/litre)
qf_{zht}	fuel consumption of conventional diesel generators (liter/MWh)
$\sum PV_{EOCK}^{GFI}$	sum of the PV of all the tax externalities (fiscal impacts) generated by the wind project (€)
q_{zht}	MWh of energy produced from installed thermal plants in each demand block h and year t "without" wind integration (MWh)
q'_{zht}	MWh of energy produced from installed thermal plants in each demand block h and year t "with" wind integration (MWh)
q_{zjt}	quantities of fuel used by each thermal generator in converted into litres/MWh in t
$\hat{q}_{wht}$	estimated MWh amount of wind energy at each demand block in t
r	financial discount rate (%)
R_{wt}^{f}, R_{wt}^{e}	financial and economic cost of grid reliability with wind, respectively (€/MWh)
t	planning years $(t,...T)$
z	set of all conventional generators in the system in year t
π_c	excise tax on carbon credits paid by the IPP (%)
τ_π	income tax paid by the IPP (%)
ρ	conversion for carbon credits (MWh to tCO_2)

A.2 Cash and Resource Flow Calculations

Cash Flow Statement – IPP's Point of View

$$FB_t^{IPP} = \sum_h^H \hat{q}_{wht} \cdot p_{wt} \cdot (1 + gp_{wt}) + \sum_h^H \sum_z^Z (q_{zht} - q'_{zht}) \cdot l_{ht} \cdot \rho \cdot p_{ct} \tag{1}$$

$$\begin{aligned} FC_t^{IPP} = {} & I_t \cdot K_{wt} + F_{wt} \cdot K_{wt} + \sum_h^H \sum_z^Z (q_{zht} - q'_{zht}) \cdot l_{ht} \cdot \rho \cdot p_{ct} \cdot \tau_c + \\ & \sum_h^H (\hat{q}_{wht} \cdot p_{wt} \cdot (1 + gp_{wt}) - F_{wt} \cdot K_{wt}) \cdot \tau_\pi \end{aligned} \tag{2}$$

$$NPV_{t=0}^{IPP} = \sum_{t=0}^{T=20} (1+r)^{-t} \left(FB_t^{IPP} - FC_t^{IPP} \right) \tag{3}$$

Cash Flow Statement – Electric Utility's Point of View

$$FB_t^{EU} = \sum_h^H \sum_z^Z \left(\frac{(q_{zht} - q'_{zht}) \cdot l_{ht}}{qf_{zht}} \right) \cdot PF_{jt}^f + (K_{zt} - K'_{zt}) \cdot F_{zt} \tag{4}$$

$$FC_t^{EU} = \sum_h^H \hat{q}_{wht} \cdot p_{wt} \cdot (1 + gp_{wt}) + \sum_h^H \hat{q}_{wht} \cdot R_{wt}^f \tag{5}$$

$$NPV_t^{EU} = \sum_t^{T=20} (1+r)^{-t} \left(FB_t^{EU} - FC_t^{EU} \right) \tag{6}$$

Resource Flow Statement – Country Economy's Point of View

$$\begin{aligned} EB_t^{CV} = {} & \sum_h^H \sum_z^Z \left(\frac{(q_{zht} - q'_{zht}) \cdot l_{ht}}{qf_{jzt}} \right) \cdot PF_{jt}^e + \sum_h^H \sum_z^Z (q_{zht} - q'_{zht}) \cdot l_{ht} \cdot \rho \cdot p_{ct} \cdot \tau_c + \\ & (K_{zt} - K'_{zt}) \cdot F_{zt} + \sum_h^H (\hat{q}_{wht} \cdot p_{wt} \cdot (1 + gp_{wt}) - F_{wt} \cdot K_{wt}) \cdot \tau_\pi \end{aligned} \tag{7}$$

$$EC_t^{CV} = \sum_h^H (\hat{q}_{wht} \cdot p_{wt} \cdot (1 + gp_{wt})) \cdot (1 + FEP) + \sum_h^H \hat{q}_{wht} \cdot R_{wt}^e \tag{8}$$

$$NPV_t^{CV} = \sum_t^{T=20} (1 + EOCK)^{-t} \left(EB_t^{CV} - EC_t^{CV} \right) \tag{9}$$

Acknowledgements

The authors wish to thank Richard Green (Imperial College London, UK), David Maddison (University of Birmingham, UK), Daniel Ralph (University of Cambridge, UK), Matthew Cole (University of Birmingham, UK), Arnold Harberger (The University of California Los Angeles, US) and Bahman Kashi (Queen's University, Canada) for providing useful feedback and sharing their analytical insights on this topic. Authors also appreciate helpful comments and discussions at the seminars, conferences and energy training programs organized by the Midlands Energy Graduate School (2013, University of Nottingham, UK; 2011, Loughborough University, UK), UK Energy Research Center (2012, University of Warwick, UK), Society for Benefit-Cost Analysis (2011, George Washington University, US), and Trade, Environment, Development and Energy Research Group of the Department of Economics (University of Birmingham, UK).

References

African Development Bank (AfDB), 2014. Cabo Verde Country Strategy Paper 2014-2018, ORWA Department/SNFO.

Alves, L., Costa A Carvalho, M., 2000. Analysis of potential market penetration of renewable energy technologies in peripheral islands. Renewable Energy. 19, 311-317.

Baylis, K., Hall, D., 2000, Independent Power Producers: A Review of Issues. University of Greenwich, PSIRU. www.psiru.org (accessed 15.11.02)

Briceño-Garmendia, C.M., Benitez, D., 2011. Cape Verde's Infrastructure: A Continental Perspective, Africa Infrastructure Country Diagnostic, Country Report, World Bank Policy Research Working Paper No. 5687. IBRD, Washington DC.

Bode, S., 2006. On the Impact of Renewable Energy Support Schemes on Power Prices, Institute of International Economics (HWWI), Hamburg.

Burer, M.J., Wustenhagen, R., 2009. Which Renewable Energy Policy is a Venture Capitalist's Best Friend? Empirical Evidence from a Survey of International Cleantech Investors. Energy Policy. 37(12), 4997–5006

Cabral, C., Vale, Z.A., Ferreira, J., Morais, H., Khodr, H., 2009. A new wind farm in Santiago Island, Cape Verde - Simulation and economic studies. IEEE PES/lAS Conference on Sustainable Alternative Energy, 1–6.

Deichmann, U., Meisner, C., Murray, S., Wheeler, D., 2011. The economics of renewable energy expansion in rural sub-Saharan Africa. Energy Policy. 39(1), 215–227.

Denholm, P. and Hand, M., 2011. Grid Flexibility and Storage Required to Achieve Very High Penetration of Variable Renewable Electricity, Energy Policy. 39(3), 1817-1830.

Denny E., O'Malley, M., 2007. Quantifying the total net benefits of grid integrated wind. IEEE Trans. Power Syst. 22(2), 605–615.

Eberhard, A., Foster, V., Briceño-Garmendia, C., Ouedraogo, F., Camos, D., Shkaratan, M., 2008. Underpowered: The State of the Power Sector in Sub-Saharan Africa, AICD Background Paper 6, Africa Region. World Bank, Washington, DC.

Eberhard, A., Gratwick, K., 2013. Investment Power in Africa, Where from and where to? Georgetown J. Int. Aff., The Future of Energy. 14(1), 39–46.

Foster, V., Steinbuks, J., 2009. Paying the Price for Unreliable Power Supplies: In-House Generation of Electricity by Firms in Africa, Policy Research Working Paper 4913. World Bank, Washington, DC.

Garcia, A., Meisen, P., 2008. Renewable Energy Potential of Small Island States. Global Energy Network Institute (GENI). http://www.geni.org/globalenergy/library/articles-renewable-energy-transmission/small-island-nations.shtml (accessed 15.11.26)

George, M., Banerjee, R., 2011. A methodology for analysis of impacts of grid integration of renewable energy. Energy Policy. 39(3), 1265-1276.

Hirst, E., Hild, J., 2004. The Value of Wind as a Function of Wind Capacity, The Electricity Journal. 17(6), 11-20.

Holttinen, H., Meibom, P., Orths, A., Lange, B., O'Malley, M., Tande, J. O., Estanquiero, A., Gomez, E., Soder, L., Strbac, G., Smith, J. C., Van Hulle, F., 2011. Impacts of large amounts of wind power on design and operation of power systems, results of IEA collaboration, Wind Energy. 14(2), 179-192.

InfraCo, (n.d.), Green Energy Generates A Brighter Future, Cabeolica Wind Farms, Cape Verde. http://www.pidg.org/resource-library/case-studies/pidg-case-study-cabeolica.pdf (accessed 15.10.05)

International Energy Outlook (IEA), 2014. Africa Energy Outlook. A Focus On Energy Prospects in Sub-Saharan Africa. World Energy Outlook Special Report. https://www.iea.org/publications/freepublications/publication/WEO2014_AfricaEnergyOutlook.pdf. (accessed 15.11.02)

Jenkins, G.P., 1999. Evaluation of stakeholder impacts in cost–benefit analysis. Impact Assess. Proj. Apprais. 17, 87-96.

Jenkins, G.P., Kuo, C.Y., Harberger, A.C., 2011a. Chapter 1: The Integrated Analysis of Investment Projects, Cost–Benefit Analysis for Investment Decisions. JDI Development Paper Series, Queen's University, DDP 2011-01.

Jenkins, G.P., Kuo, C.Y., Harberger, A.C., 2011b. Chapter 2: A Strategy for the Appraisal of Investment Projects, Cost–Benefit Analysis for Investment Decisions. JDI Development Paper Series, Queen's University, DDP 2011-02.

Jensen, P. and Stonecash, R., 2005. "Incentives and the Efficiency of Public Sector Outsourcing Contracts" Journal of Economic Surveys. 19, 766-787.

Karekezi, S., Kimani, J., 2002. Status of Power Sector Reform in Africa: Impact on the Poor. Energy Policy. 30(11-12), 923-945.

Karki, R., Billinton, R., 2004. Cost–Effective Wind Energy Utilization for Reliable Power Supply. IEEE Trans. Energy Convers. 19(2), 435–440.

Kennedy, S., 2005. Wind Power Planning: Assessing Long-Term Costs and Benefits. Energy Policy. 33(13), 1661–1675.

Krohn, S., Morthost, P. E., Awerbuch, S., 2009. The Economics of Wind Energy, European Wind Energy Association (EWEA), Brussels.

Kuo, C.Y., Salci, S., Jenkins, G.P., 2015. Measuring the Foreign Exchange Premium and the Premium for Non-Tradable Outlays for Countries in Africa. South Afr. J. Econ. 83(2), 269–285.

Lamont, A.D., 2006. Assessing the Long-Term System Value of Intermittent Electric Generation Technologies. Energy Econ. 30(3), 1208–1231.

Lesser, J.A., Su, X., 2008. Design of an Economically Efficient Feed-In Tariff Structure for Renewable Energy Development. Energy Policy 36, 981.

Lew, D., Milligan, M., Piwko, D., Jordan, G., 2011. The value of wind power forecasting, National Renewable Energy Laboratory, NREL.

Lock, R., 1995. Financing of Private Power Development and Power Sector Reform in Emerging Nations: An Essential Nexus? Energy Policy. 23(11), 955–965.

Lund, H., 2005. Large-Scale Integration of Wind Power into Different Energy Systems. Energy. 30(13), 2402–2412.

Lund, H., Munster, E., 2003. Modelling of energy systems with a high percentage of CHP and wind power. Renew. Energy 28(14), 2179–2193.

Lundsager, P., Hansen, J.C., 2002. High Penetration of Wind Energy into Island Diesel Grids Experience from Cape Verde. Wind Diesel Workshop 2002, Anchorage, Alaska, 23–24 September 2002.

MacCormack, J., Hollis, A., Zareipour, H., Rosehart, W., 2010. The large-scale integration of wind generation: Impacts on price, reliability and dispatchable conventional suppliers. Energy Policy. 38(7), 3837–3846.

Moran, D., Sherrington, C., 2007. An Economic Assessment of Wind Farm Power Generation in Scotland Including Externalities. Energy Policy. 35(5), 811–825.

Norgard, P., Fonseca, J., 2009. Ultra high wind penetration in simple wind-diesel power systems in Cape Verde. In Proc. EWEC

Oseni, M., Pollitt, M., 2013. The Economic Costs of Unsupplied Electricity: Evidence from Backup Generation among African Firms. EPRG Working Paper, No.1351.

Phadke, A.. 2009. How Many Enrons? Mark-ups in the stated capital cost of independent power producers' (IPPs) power projects in developing countries. Energy, 34(11), 1917-1924.

Ranaboldo, M., Domenech Lega, B., Vilar, D., Ferrer Marti, L., Pastor Moreno, R., Garcia Villoria, A., 2014. Renewable Energy Projects to Electrify Rural Communities in Cape-Verde. Appl. Energy. 118, 280–291.

Simonsen Associados Sociedade Comercial Ltda. E Euroventures Consultoria LTDA., 2008. Estudo de Demanda de Energia em Cabo Verde. Praia.

Touhy, A., Meibom, P., Denny, E., O'Malley, M., 2009. Unit commitment for systems with significant wind penetration, IEEE Transactions on Power Systems. 24(2), 592-601.

United Nations, 2012. Clean Development Mechanism. http://www.un.cv/files/ONE%20UN%20Annual%20report%202012.pdf (accessed 15.11.25)

United Nations, 2006. Clean Development Mechanism. https://cdm.unfccc.int/filestorage/f/b/FZJNR170L5CE3YDVM86UTWIXPKOAHS.pdf/9570%20PDD.pdf?t=Z0h8bzU4azdtfDACs7v_6Lr36EN8wXfko1BI (accessed 14.07.01)

Weiss, J., Sarro, M., 2013. The importance of long-term contracting for facilitating renewable energy project development. The Brattle Group, Inc. http://www.brattle.co.uk/system/publications/pdfs/000/004/927/original/The_Importance_of_Long-Term_Contracting_for_Facilitating_Renewable_Energy_Project_Development_Weiss_Sarro_May_7_2013.pdf?1380317003 (accessed 15.11.03)
Weisser, D., 2004. Power sector reform in small island developing states: what role for renewable energy technologies? Renew. Sustain. Energy Rev. 8, 101–127.
Wiser, R., Pickle, S., 1998. Financing investments in renewable energy: the impacts of policy design. Renew. Sustain. Energy Rev. 2(4), 361–386.
World Bank, 2011. Project Appraisal Document on a Proposed Load in the Amount of Euros 40.2 Million to the Republic of Cape Verde for a Recovery and Reform of the Electricity Sector Project. http://www-wds.worldbank.org/external/default/WDSContentServer/WDSP/IB/2011/12/29/000020439_20111229091225/Rendered/PDF/582180PAD00PUB090201200R20110027901.pdf (accessed 15.10.16)
World Bank, 2014. Worldwide Governance Indicators. info.worldbank.org/governance/wgi/index.aspx#home (accessed 15.11.18)
World Bank, 2015. Cape Verde. http://www.worldbank.org/en/country/caboverdee (accessed 15.11.26)